AEMO Victorian Planning

Transgrid

Victoria to New South Wales Interconnector West

July 2022

Regulatory Investment Test for Transmission

Project Assessment Draft Report

Important notice

Purpose

The Australian Energy Market Operator Limited (AEMO) and NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Networks Operations Trust trading as Transgrid (Transgrid) have prepared this Project Assessment Draft Report to meet the consultation requirements of clauses 5.16A.4(c) – (h) of the National Electricity Rules.

Disclaimer

This document or the information in it may be subsequently updated or amended.

This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules or any other applicable laws, procedures or policies. AEMO and Transgrid have made every reasonable effort to ensure the quality of the information in this document but cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO, Transgrid and their respective officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

Locations

Descriptions and visual representations of geographic locations in this document are indicative only. Locations will be determined after the conclusion of the RIT-T process, as required during detailed design, route assessment, planning and community engagement phase.

Copyright

© 2022 Australian Energy Market Operator Limited and NSW Electricity Networks Operations Pty Limited ACN 609 169 959 as trustee for NSW Electricity Networks Operations Trust ABN 70 250 995 390 trading as Transgrid. The material in this publication may be used in accordance with the copyright permissions on AEMOs' website (but as if a reference in those permissions to "AEMO" read "AEMO and Transgrid").

Version control

Version	Release date	Changes
#1	29/7/2022	

AEMO and Transgrid acknowledge the many First Nations that host Australia's electricity grids and pay respect to Elders past, present and emerging. We respect the Indigenous history of the lands in which we currently and plan to operate, being conscious of the landscape-scale impacts of the energy transition. We wish to emphasise the importance of early and continued engagement, working closely with Traditional Owners, as the grid seeks to expand.

Executive summary

Under its declared network functions – including for Victorian transmission planning – set out in the National Electricity Law (NEL), AEMO Victorian Planning (AVP) is responsible for planning and directing augmentation on the Victorian electricity transmission Declared Shared Network (DSN). Transgrid operates and manages the high voltage electricity transmission network in New South Wales and the Australian Capital Territory and is the Jurisdictional Planning Body for New South Wales.

AVP and Transgrid are jointly investigating options to increase the capacity to share electricity between Victoria and New South Wales. This will help harness clean low-cost electricity from renewable energy zones (REZs) in both states and make better use of Snowy 2.0's deep storage, thereby helping to reduce carbon emissions and improving the reliability and security of electricity supply as ageing coal-fired power stations close.

This Regulatory Investment Test for Transmission (RIT-T) will determine if the anticipated market benefits from a new interconnector outweigh the estimated cost to energy consumers. This assessment involves evaluating the technical and economic feasibility of a new transmission link between Victoria and New South Wales, together with credible non-network options. As an important step in the RIT-T process, this Project Assessment Draft Report (PADR) identifies and seeks consultation and feedback on the proposed preferred option that maximises net market benefits in the long-term interest of consumers.

Critically important environmental, social and cultural matters have been considered to the extent possible at this early stage, based on publicly available information, noting that the route is not yet determined. Learnings from recent RIT-Ts have reinforced the importance of early and meaningful engagement with communities and landholders in order to find mutually beneficial solutions, where possible, for those that may be required to host linear infrastructure. These learnings with respect to stakeholder engagement are being applied in this RIT-T.

Overview

Victoria – New South Wales Interconnector (VNI) West (via Kerang), referred to as 'VNI West', is a proposed new high capacity 500 kilovolt (kV) double-circuit overhead transmission line between Victoria and New South Wales. The project would connect the Western Renewables Link (WRL)[1] (at the proposed terminal station north of Ballarat) with Project EnergyConnect (at Dinawan) via new stations near Bendigo and Kerang, and is currently estimated to cost $3.256 billion[2]. The 2022 *Integrated System Plan* (ISP) identifies VNI West as an actionable ISP project to be progressed urgently[3].

VNI West is the proposed preferred option identified under this PADR. This PADR confirms that VNI West would provide a positive net market benefit of $687 million, in net present value terms, compared with the counterfactual case without VNI West.

---

[1] Formerly the Western Victoria Transmission Network Project, now renamed by AusNet Services.

[2] The VNI West cost estimates used in this PADR differ from those presented in the 2022 ISP by approximately $300 million due to contingency cost additions made in anticipation of some level of route diversion, tower redesign, or screening beyond that considered in the 2022 ISP cost estimate. This contingency cost provision does not anticipate undergrounding costs. If partial undergrounding is required in exceptional circumstances, a greater level of cost contingency would be needed.

[3] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. "Actionable" in an ISP means AEMO has identified that there are consumer benefits to the project being initiated as soon as possible, before the next two-yearly ISP is published.

The PADR assessment also considered an option combining VNI West with a non-network virtual transmission line (VTL) comprising battery storage near Sydney and Melbourne which would allow the existing VNI to be operated at a higher capacity. The PADR finds that the VTL option would not increase overall expected net market benefits, and that VNI West alone has approximately 19% greater estimated net benefits than if it were combined with a VTL[4].

The analysis shows that, compared to a future without this project, the preferred option is expected to efficiently provide supply reliability and put downward pressure on electricity prices by:

- Reducing and deferring the need for new dispatchable generation/storage investment to meet demand.
- Lowering aggregate fossil fuel usage required for generation to meet demand in the National Electricity Market (NEM) going forward, thereby reducing fuel costs.

VNI West aligns with the ISP actionable project that forms part of the optimal development path in the 2022 ISP. The 2022 ISP describes VNI West as a single actionable ISP project, noting that staging of the project through use of feedback loops[5] will protect consumers from risks of over- or under-investment:

- Stage 1: to carry out early works immediately for completion as soon as possible.
- Stage 2: to complete implementation of the project.

The early works in Stage 1 may include project initiation, land-use planning, detailed engineering design, route development, biodiversity offset strategy, cost estimation, and strategic network investments such as the enhancement of Project EnergyConnect[6]. Early works will provide an opportunity to engage with and consult communities and stakeholders on a range of matters. These works also will reduce cost uncertainties and provide greater confidence to consumers that they will not be over- or under-investing in this key project.

The RIT-T is an economic cost benefit test. Under the National Electricity Rules (NER), the scope of the RIT-T is limited to determining if a project will deliver net market benefits to the NEM as a whole. The RIT-T process is monitored and enforced by the Australian Energy Regulator (AER). The environmental, land-use, safety, amenity, social, cultural and community matters raised by stakeholders are important considerations that, if not appropriately taken into account, will result in higher project costs which would lower benefits for consumers. At the RIT-T stage, these factors can only be considered at a high level using desktop studies, because the route (and therefore the potentially impacted communities) is not determined until after the RIT-T is finalised. As a result, allowances have been made in the cost to accommodate adjustments to the project such as route detours that may later be determined to be needed to mitigate adverse environmental or social impacts.

These important environmental, social and cultural matters will be given due consideration and addressed through extensive community and stakeholder consultation as part of design and planning approvals processes. The intent is to avoid and minimise project impacts where possible, while ensuring the project continues to deliver the expected market benefits in the long-term interest of electricity consumers.

[4] This percentage has been calculated based on the estimated weighted net market benefits of the two credible options.

[5] In the ISP feedback loop, AEMO (in its national planning function) re-assesses the preferred option from the RIT-T considering any new and relevant information, and confirms if it remains aligned with the optimal development path in the most recent ISP.

[6] The Federal Government has underwritten funds to build a component of Project EnergyConnect at a larger capacity such that it removes the need to duplicate lines for VNI West when it is constructed. See https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw.

The power system in eastern Australia is undergoing fundamental, rapid and complex change. The integration of renewable generation and adoption of new technologies continues to shift the geography and technical characteristics of electricity supply in Victoria and New South Wales, and is essential for the Australian economy to achieve net zero emissions by 2050. Concurrently, the forecast closure of ageing coal-fired generators in Victoria and New South Wales over the coming decades presents a significant challenge to supply reliability for the energy industry. Recent announcements by EnergyAustralia[7], Origin Energy[8] and AGL[9] reinforce the risk of withdrawal of coal-fired generators from the market before previously announced retirement dates.

Targeted investment in transmission infrastructure is critical to adapt to these changes and harness Australia's rich renewable energy resources in a cost-effective manner to deliver benefits to consumers across the NEM.

In response to this fundamental transition in the energy system, AEMO (in its role as national transmission planner) is required under the regulatory and planning framework to publish an ISP at least every two years. The ISP serves as a whole-of-system plan and provides a roadmap for development in eastern Australia's electricity system that responds to the latest technology, economic shifts and policy developments. It identifies network investments that AEMO considers to be key to successfully underpinning the energy market transition (the 'optimal development path') and requires the RIT-T to be applied to those projects that are the actionable ISP projects, to progress in the near term.

The 2022 ISP outlines two stages to VNI West[10]:

- Stage 1 is to carry out the early works immediately for completion as soon as possible.
- Stage 2 is to complete implementation of the project.

The first stage – early works – is expected to take three to four years to complete, and may include project initiation, land-use planning, detailed engineering design, route development, biodiversity offset strategy, cost estimation, and strategic network investments, such as the enhancement of Project EnergyConnect[11]. Early works will provide an opportunity to engage with and consult communities and stakeholders on a range of matters. The works will also reduce cost uncertainties and provide greater confidence to consumers that they will not be over- or under-investing in this key project. Some early works in New South Wales are currently underway and have been supported via underwriting by the Federal Government announced in early April 2022.

The 'identified need' for the VNI West project is to increase transfer capacity between New South Wales and Victoria to realise net market benefits by[12]:

- Efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in ageing generator reliability – including mitigation of the risk that existing plant closes earlier than expected.
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales through improved network capacity and access to demand centres.
- Enabling more efficient sharing of resources between NEM regions.

---

[7] At https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition.

[8] At https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

[9] AGL has updated the expected closure year for Bayswater and Loy Yang A power stations in New South Wales and Victoria respectively.

[10] AEMO, 2022 ISP, June 2022, p. 74. The final 2022 ISP removed the formal decision rules for VNI West (via Kerang) included in the Draft 2022 ISP.

[11] AEMO, 2022 ISP, June 2022, p. 75.

[12] AEMO, 2020 ISP, July 2020, p. 87.

Meeting this need is expected to put downward pressure on energy costs by lowering overall power system investment and dispatch costs across the NEM. The investment will also provide interconnector diversity[13], which increases the resilience of the grid against extreme climate conditions and improves overall system security.

Stakeholder feedback on the PSCR has been taken into account in this PADR

AVP and Transgrid formally commenced this RIT-T by publishing the Project Specification Consultation Report (PSCR) in December 2019, before the new actionable ISP framework came into effect.

In total, 24 formal submissions were received in response to the PSCR, 20 of which have been published on AEMO's website (four submitters requested confidentiality)[14]. Notwithstanding the length of time that has elapsed since the publication of the PSCR, and the subsequent further analysis and direction provided via the ISP process, many of the issues raised in submissions remain relevant to this PADR.

While submissions covered a range of topics, the nine broad topics most commented on were:

- The scope of the options included in the assessment.
- Support for an accelerated delivery of the preferred option.
- Consideration of non-network options.
- Interaction with other major transmission investments.
- Accuracy of the option cost estimates.
- Interaction with the Victorian Big Battery.
- Costs and benefits captured in the assessment.
- The identified need and the amount of increased transfer capacity.
- Social impacts and network topology considerations.

Before as well as after receiving submissions, AVP and Transgrid offered to meet with all submitters to the PSCR and held bilateral meetings with a broad range of interested parties including consumer representatives, manufacturers, developers, financiers, generators, retailers, government departments, local government areas (LGAs), and network service providers (NSPs) to further discuss the RIT-T assessment. These meetings played a pivotal role in defining and undertaking the assessment presented in this PADR, including in relation to the consideration of a VTL component and the inclusion of power flow control technology.

AVP and Transgrid have taken all relevant feedback raised in submissions and earlier stakeholder feedback sessions into account in undertaking the PADR analysis, and have included in this report a response to each of the points raised.

Key developments since the PSCR have been reflected in this PADR

There have been a range of other key developments since the PSCR was released, including:

- The implementation of the 'actionable ISP' framework in mid-2020.

[13] Having multiple physical interconnector routes between Victoria and New South Wales with no geographic points in common.

[14] See https://aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission/stakeholder-consultation.

- Consultation on, and finalisation of, updated assumptions and scenarios that were applied in the 2022 ISP[15].
- The development and commissioning of the Victorian Big Battery.
- Project EnergyConnect RIT-T approved by the AER in January 2020 and a Contingent Project Application (CPA), or funding application, was approved in May 2021.
- Commitment by Transgrid (supported by underwriting by the Federal Government) in September 2021 to the Dinawan to Wagga Wagga portion of Project EnergyConnect being built at 500 kV to lower the subsequent costs for expanding interconnection between Victoria and New South Wales.
- Identification by AusNet Services of the proposed route for Western Renewables Link in November 2021
- Federal Government underwriting of New South Wales early works on VNI West in April 2022.
- Additional early closures announced for coal power plants following the publication of the Draft 2022 ISP (specifically, AGL and Origin Energy announcing in February 2022 that they have accelerated their closure timelines for Loy Yang A, Bayswater and Eraring).
- Continuing confirmation in the Draft (and final) 2022 ISP that VNI West remains on the optimal development path and should be progressed as an actionable ISP project.
- Elimination of some previously identified credible options from further RIT-T evaluation (such as the route in close proximity to Shepparton) through the 2022 ISP analysis.
- New scenarios and scenario weightings from the 2022 ISP, with the *Step Change* scenario being selected by stakeholders through a Delphi process as the most likely scenario.

These developments have had a material impact on the assessment under this RIT-T and have been reflected in the PADR assessment.

Two options have been assessed in this PADR

This PADR assesses two different options to provide additional transfer capacity between Victoria and New South Wales, which reflect the 2022 ISP candidate option selected as actionable in the optimal development path and the use of alternative technologies:

1. VNI West – a new high capacity 500 kV double-circuit overhead transmission line to connect the Western Renewables Link (north of Ballarat) with Project EnergyConnect (at Dinawan) via new stations near Bendigo and near Kerang[16].
2. A VTL commissioned ahead of VNI West (which would continue to form part of this option), involving batteries at South Morang in Victoria and Sydney West in New South Wales. This option has arisen from submissions to the PSCR and subsequent detailed network analysis by AVP and Transgrid.

The Western Renewables Link and Project EnergyConnect are currently under development. For the purpose of this RIT-T, they are treated as anticipated projects and assumed to be delivered in a timely manner to enable VNI West to connect efficiently to the network. If there are any modifications to Western Renewable Link or Project EnergyConnect through their development processes, the impact of these modifications will be assessed to

[15] See https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios.

[16] VNI West (via Kerang) is a refinement of the 'VNI 7' option presented in the PSCR.

determine if any consequential changes to VNI West would be required that could materially change this RIT-T assessment.

To avoid duplication with the ISP, credible options included in the PSCR that AEMO already considered would not form part of the Draft (and final) 2022 ISP optimal development path are not re-assessed in this PADR. This PADR summarises the further analysis undertaken by AEMO as part of the ISP process in relation to these other options, to provide transparency and continuity with the PSCR.

Options to underground the lines were raised in submissions to the PSCR, and continue to be suggested by stakeholders and communities as possible solutions that could help minimise social and environmental impacts of the project. Overhead transmission lines and underground cables can be high voltage alternating current (HVAC) or high voltage direct current (HVDC) technology:

- HVAC is flexible to support a 'meshed' network and is adaptable to enable the connection of new equipment.
- HVDC can be a superior option to enable point-to-point interconnection, such as Basslink or Murraylink, or to connect a single project into the network, and is typically cheaper than underground HVAC for these purposes.

VNI West will form part of the overall electricity transmission network delivering electricity from where it is generated to where it is used and facilitating the wholesale electricity market to deliver reliable and affordable electricity to homes and businesses. VNI West is not a point-to-point connecting link, but an integral part of the electricity transmission network. HVDC technology has therefore been ruled out as an option for VNI West, as additional costly converter stations to convert between direct current and alternating current would be required in the future for other connections anticipated to be required along the route. This was discussed in the 2020 ISP, reconfirmed in the 2022 ISP, and is further discussed in this PADR.

HVAC is the superior technology type for VNI West, as a key driver of the project is enabling integration with the existing network, and facilitating the connection of new renewable energy generation. However, based on current cost assumptions, delivery of high-capacity HVAC 500 kV underground lines along the full length of the project is not economically justifiable under the RIT-T, with HVAC undergrounding costing in the order of at least 10-20 times more than overhead[17]. Significant third party funding commitments (or other interventions) would be required if undergrounding was deemed necessary to balance the cost of investment imposed on electricity consumers with the burden of hosting linear infrastructure for landholders and regional communities. The cost range is broad because these costs are project specific due to different technical requirements and are heavily dependent on the need for transition stations, line capacity, terrain and competing land uses.

AVP and Transgrid acknowledge the importance of considering all reasonably practicable route refinement options, which may, in exceptional circumstances, include partial undergrounding over short distances. The factors to be considered are route-specific and can therefore only be investigated, and remediation options considered, as part of the project's early works stage, following the RIT-T process.

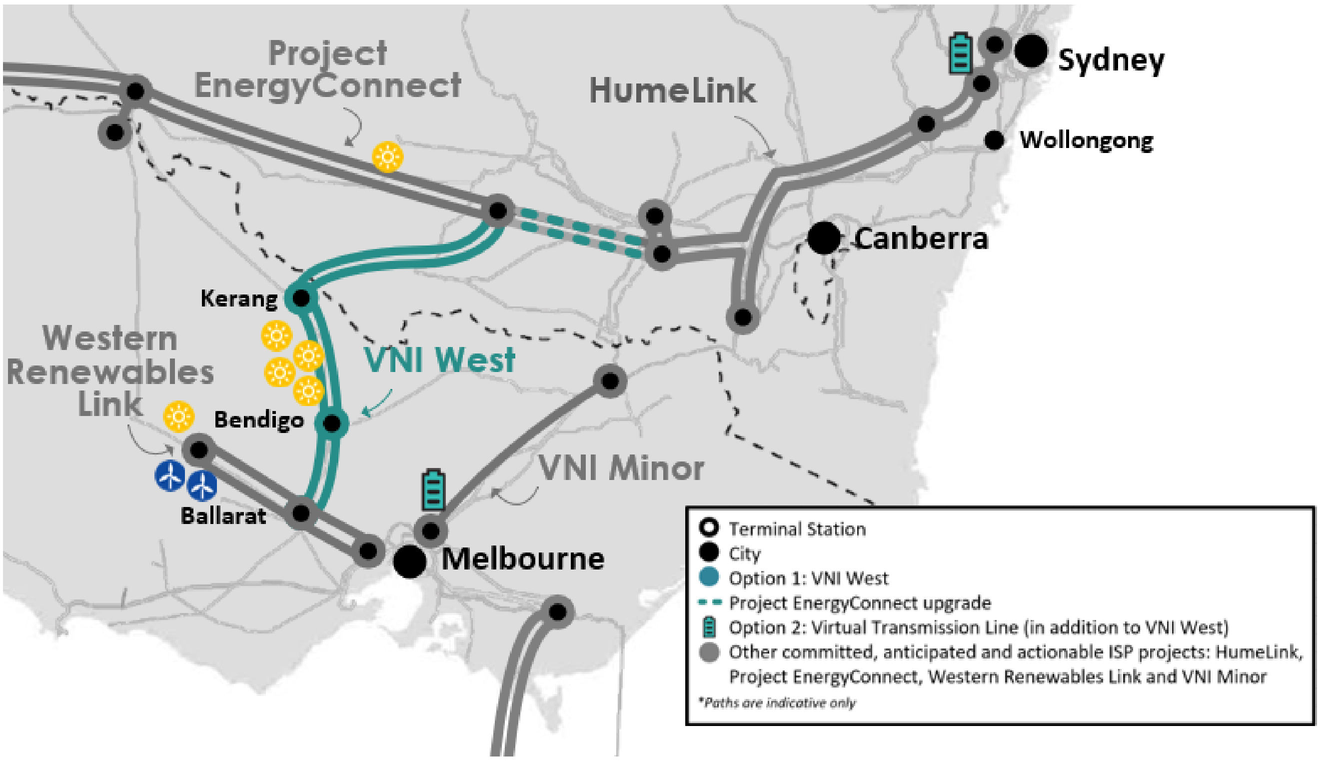
Figure 1 shows the two credible options considered in this PADR and their proximity to other major ISP projects and REZs[18]. The topologies shown are high-level schematic illustrations only, and specific line routes are not defined within the PADR[19].

[17]There are a range of public references comparing overhead HVAC and underground HVAC costs. The range referenced is guided by the ISP Cost Database, which has been consulted on, see https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

[18] For a diagram of REZ development in the ISP, see AEMO, 2022 ISP, June 2022, p. 44.

[19] A specific route for the preferred option will only be confirmed following completion of the PACR.

Figure 1 Credible options assessed



The technical characteristics of the credible options are summarised in Table 1, which shows the indicative impact on transfer capacity (in both directions), the REZ transmission limit (by affected REZ), and the expected capital cost for each option (in both Victoria and New South Wales).

Table 1 Summary of the credible options assessed in this PADR

Option	Indicative impact on transfer capacity		REZ transmission limit	Capital cost, $m in FY2020-21 dollars*	
	VIC to NSW	NSW to VIC		VIC	NSW
Option 1 – VNI West	+1,930 megawatts (MW)	+1,800 MW	V2 - Murray River: +1,600 MW V3 - Western Vic: +550 MW N5 – South West NSW: +900 MW	$1,605 million	$1,651 million
Option 2 – VTL ahead of VNI West	+250 MW from the VTL +1,930 MW from VNI West	+250 MW from the VTL +1,800 MW from VNI West	Same as VNI West once it is commissioned (that is, no additional REZ hosting capacity associated with VTL component)	$1,918 million	$1,957 million

* While the capital costs are shown at an aggregate state-level in this table, they have been broken out by key cost category for each option in the body of the PADR; that is, early works, substation works, line works, battery costs (for the VTL option), power flow controllers, property/land access/easements and biodiversity offset costs. The Option 2 capital costs are also inclusive of battery replacement costs that will be incurred in 2047. The PADR also explains how each of these categories has been estimated and updated since the PSCR.

The options have been assessed using three scenarios consulted on and finalised for the 2022 ISP

The actionable ISP framework requires RIT-T assessments to use ISP parameters, including the scenarios, inputs and assumptions that have been developed through consultation as part of the ISP. The three scenarios identified in the 2022 ISP as relevant for VNI West (and the corresponding weights required to be applied in the PADR analysis) are[20]:

- *Step Change* scenario (52%) – rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action.
- *Progressive Change* scenario (previously *Net Zero 2050*) (30%) – pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time.
- *Hydrogen Superpower* scenario (18%) – strong global action and significant technological breakthroughs with a near quadrupling of NEM energy consumption to support a hydrogen export industry.

VNI West is the preferred option at this stage of the RIT-T

The results of the PADR assessment found that commencing early works as soon as possible and having VNI West operational by July 2031 under the most likely (*Step Change*) scenario delivers approximately $687 million of scenario weighted net market benefits for consumers. It has significant positive net market benefits under the *Step Change* (delivered by July 2031) and *Hydrogen Superpower* (delivered by July 2030) scenarios, and marginally negative net market benefits under the *Progressive Change* scenario (delivered by July 2038). On a scenario weighted basis, VNI West was found to deliver $108 million, or 19%, greater net market benefits than Option 2 that also includes the VTL from 2026 until VNI West is delivered.

The increased transfer capacity under both options is forecast to harness diverse variable renewable energy (VRE) resources and promote the efficient sharing of energy and capacity between southern regions, particularly Victoria and New South Wales. With VNI West in place, compared to the 'do nothing' base case:

- The Murray River REZ is projected to build substantially higher solar capacity (between 2.3 gigawatts [GW] and 2.6 GW across the three scenarios).
- The Western Victoria REZ is projected to build a greater quantity of wind capacity (between 600 MW and 800 MW across the three scenarios).
- The South-West New South Wales REZ is projected to build more solar and wind capacity, particularly under the *Step Change* and *Progressive Change* scenarios (approximately 85 MW to 800 MW across the three scenarios).

The additional renewable capacity build, compared to the base case, is higher than the increase in REZ transmission limits facilitated by VNI West (shown in Table 1). This is because not all the generation will be operating at full capacity all of the time, and the modelling strikes a balance between small amounts of generation curtailment and efficient utilisation of REZ transmission capacity.

Changes in resource sharing and better utilisation of Snowy pumped hydro, particularly Snowy 2.0, is found to defer and reduce the need for investment in new capacity, as well as deliver significant fuel cost savings by offsetting thermal generation that would otherwise need to operate.

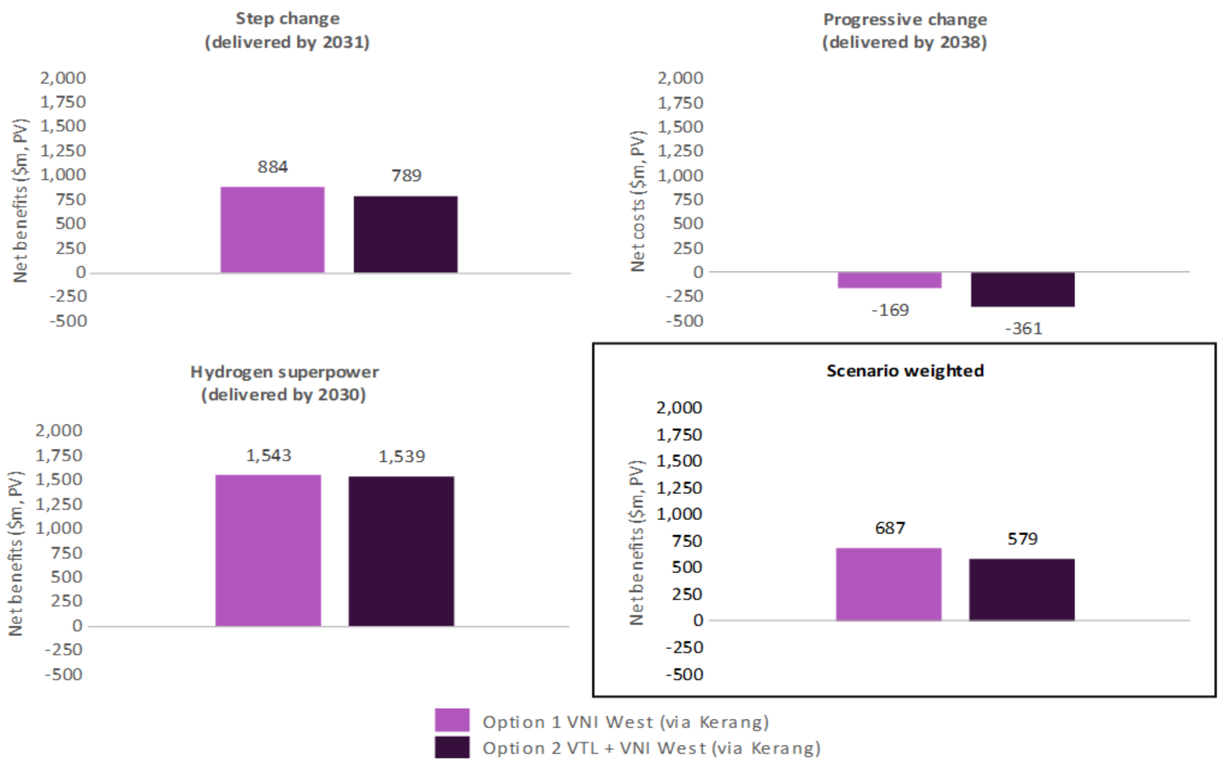
In all three scenarios, the vast majority of benefits are from avoided or deferred generation and storage capital costs and avoided fuel costs (which, together, make up between 83% and 94% of Option 1's gross benefits across the three scenarios). Avoided transmission costs associated with the connection of REZs make up the remainder of the estimated benefits.

[20] For a full description of these scenarios, see AEMO, 2021 IASR, July 2021, p. 5.

The finding that Option 1 is the preferred option is robust to a range of sensitivity tests undertaken as part of this PADR, including higher network capital costs and lower VTL battery costs. Further, boundary testing indicates that, assuming no other changes, network capital costs would need to increase by more than 45% (that is, from $3,256 million to $4,710 million) for the investment to not provide a scenario-weighted positive net market benefit.

AVP and Transgrid further find that the capital costs of the VTL battery components in Option 2 would need to fall by 38% (that is, from $540 million to $333 million) for it to have the same estimated net benefits as Option 1 on a weighted basis[21].

Figure 2 Net market benefits (net present value) comparison of credible options assessed



Note: the 'delivered by' dates above refer to VNI West and, in each case, refer to 1 July of the stated year. In all scenarios, early works commence as soon as possible, but in *Progressive Change*, Stage 2 is not delivered until 2038. The VTL component of Option 2 is assumed to be commissioned on 1 July 2026 in all three scenarios given that a decision to invest in this component would need to be made soon, before scenario uncertainties reveal themselves.

Social and environmental considerations

AVP and Transgrid recognise the vital role that community and landholders have in the planning and delivery of major transmission infrastructure projects, and are dedicated to continuously improving their engagement practices.

Transgrid recently conducted a review of the engagement processes used in previous projects to better understand the experience of impacted landholders and communities and determine improvements for future project consultation. AVP has also reflected on recent experience, and points of view from multiple stakeholder perspectives with respect to lessons learned through the ongoing Western Renewables Link community and landholder engagement, and other comparable projects.

[21] Excludes connection costs and land/easement costs relating to the VTL batteries.

Learnings and feedback from multiple stakeholders are shaping, and will continue to guide, improvements to the development of Community and Stakeholder Engagement Plans for this VNI West project.

Based on this ongoing feedback, AVP and Transgrid will:

- Engage early, listen and communicate with honesty and integrity to understand views and concerns.
- Involve stakeholders in the design of engagement approaches.
- Be clear about the engagement process and opportunities for all stakeholders and provide ample notices of consultation or engagement opportunities to facilitate meaningful participation.
- Ensure project information is accessible through a variety of channels including websites and other platforms, and that any information can be easily understood.
- Provide timely feedback regarding how stakeholder ideas and concerns are being taken into account.

We are committed to working with stakeholders and communities from an early stage, to build our understanding of the local context, listen to concerns, and help refine transmission line route options. We want to ensure that the people living and working nearby have the opportunity to participate in shaping an outcome that is socially acceptable while meeting the needs of consumers.

As part of this commitment, AVP and Transgrid will engage with regional stakeholder representatives throughout the RIT-T process to facilitate early community input on potential social and other impacts of the proposed preferred option at this stage. Discussions have already commenced with a number of councils at this early stage, including Campaspe, Edward River, Federation, Gannawarra, Greater Bendigo, Hepburn, Lockhart, Loddon, Mount Alexander, Murray River, Murrumbidgee, and Wagga Wagga. An indicative timeline for engagement in processes beyond the RIT-T is under development and will be published with the Project Assessment Conclusions Report (PACR) to give regional stakeholders ample time to prepare for meaningful engagement should the RIT-T be successful. At all times, AVP and Transgrid will be guided by the Energy Charter's *Better Practice Landholder and Community Engagement Guide*, developed with the help of landholders and community representatives, to ensure engagement with these stakeholders is respectful and fair.

A desktop land, planning and environmental feasibility analysis has been undertaken since the PSCR to better understand the existing and known conditions relevant to the credible options in this RIT-T assessment. AVP and Transgrid identified this analysis as a key step, usually not undertaken in this detail during the RIT-T process, in identifying and understanding relevant environmental and social values. Through this analysis, AVP and Transgrid identified a range of significant environmental, cultural and social constraints and opportunities, in the broad geographical area north of Ballarat up to the Victoria – New South Wales border and onto the Dinawan substation location in New South Wales, which may have significant impacts on the delivery of the credible options. These constraints were then designated as 'no-go areas', with avoidance measures being applied to the credible options and considered within the prepared cost estimates, to further enhance the accuracy of the estimates. AVP and Transgrid also identified areas that have previously been disturbed where potential impacts on existing and future land-use could be minimised, such as co-locating with existing linear infrastructure. The outcome of this process was the refinement of the broad geographic area to an 'area of interest'.

If a project is confirmed through the RIT-T process, the development of a project route and the location of any proposed terminal stations will be determined through a rigorous route and site selection process, detailed design, and community and landholder consultation. As part of the future route determination exercise, this desktop analysis would be validated and undergo more focused assessments, surveys and discussions to further investigate environmental, cultural and social constraints and opportunities. This will allow the reduction of this area of interest to an 'investigation corridor'.

The proposed route and associated infrastructure would also be subject to the requirements of the relevant planning and environmental approval processes. In support of these processes, the potential impacts associated with the construction and operation of VNI West would be further assessed. This includes working with landholders in the identified investigation corridor to gain a deeper understanding of the existing local constraints and opportunities for mutual benefits. The aim is to create a shared vision of the ideal route within the investigation corridor.

Further information and next steps

All stakeholders are welcome to provide written submissions on the PADR including comments on the analysis and ranking of the preferred option. All forms of feedback will be carefully considered in the preparation of the final report (the Project Assessment Conclusions Report [PACR]) and all written submissions will be published online, along with a summary of how feedback has been taken into account.

Submissions are due on or before 9 September 2022 and should be emailed to VNIWestRITT@aemo.com.au.

A series of forums and briefings will be held prior to submissions closing, to provide stakeholders with a detailed understanding of the PADR and next steps. Information regarding the submission process (including how to make a submission) and upcoming stakeholder engagement activities will be published on the VNI West dedicated webpage on AEMO's website at https://aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission. If you do not want your submission to be publicly available, please clearly stipulate this at the time of lodgement.

The final step of the RIT-T process, the PACR, will include the matters outlined in this PADR and consideration of any submissions made in response to this PADR. The PACR is targeted for publication in late 2022.

Contents

Tables

Figures

1 Introduction

The Regulatory Investment Test for Transmission (RIT-T) is an economic cost benefit test used to assess and rank different network and non-network investment options that address an identified power system need. This Project Assessment Draft Report (PADR) is the next step in the detailed consultation process in relation to expanding the Victoria – New South Wales Interconnector (VNI) West RIT-T, which is identified as an 'actionable ISP project' in the 2022 *Integrated System Plan* (ISP)[22].

1.1 Overview of this report

The power system in eastern Australia is undergoing fundamental, rapid and complex change as it transitions to net zero emissions. The integration of renewable generation and adoption of new technologies continues to shift the geography and technical characteristics of electricity supply in Victoria and New South Wales. Concurrently, the forecast closure of ageing coal-fired generators in Victoria and New South Wales over the coming decades presents a significant challenge to supply reliability for the energy industry. This challenge is further increasing with the latest round of announced coal-fired generator closures[23].

In response to this fundamental transition in the energy system, AEMO is required under the regulatory and planning framework to publish an ISP at least every two years. The ISP identifies network investments that AEMO considers to be key to successfully underpinning the energy market transition (the 'optimal development path') and requires the RIT-T to be applied to those projects that are the priority, actionable ISP projects, to progress in the near term.

The opportunity to increase interconnection between Victoria and New South Wales was included as part of the 2018 ISP, referred to as SnowyLink[24]. VNI West[25] was identified as an 'actionable ISP project' in the 2020 ISP[26] and this status continued in the 2022 ISP[27].

Targeted investment to increase the interconnection capacity between the two states will facilitate the efficient dispatch of new and existing generation, and help maintain supply reliability in Victoria. This is expected to put downward pressure on energy costs by lowering overall power system investment and dispatch costs across the National Electricity Market (NEM). The investment will also provide interconnector diversity by creating multiple

---

[22] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp.

[23] AGL Energy, *ASX and Media Release – 1H22 Results Announcement*, 10 February 2022, at https://cdn-api.markitdigital.com/apiman-gateway/ASX/asx-research/1.0/file/2924-02485194-2A1355883?access_token=83ff96335c2d45a094df02a206a39ff4 and Origin Energy, *Media release – Origin proposes to accelerate exit from coal-fired generation*, 17 February 2022, at https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

[24] AEMO, 2018 ISP, July 2018, pp 8-9, 86-88 & 90-92. At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2018-integrated-system-plan-isp.

[25] 'VNI West (via Kerang)' is the actionable ISP project and ISP candidate option included in the 2022 ISP. While the 2022 ISP, and this PADR (in limited instances), uses 'VNI West' and 'VNI West (via Kerang)' interchangeably, this is a carryover from the PSCR and 2020 ISP where there was more than one network option being considered.

[26] AEMO, 2020 ISP Appendix 3. Network investments, July 2020, p 14. At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

[27] AEMO, 2022 ISP, June 2022, p 75.

physical interconnector routes between Victoria and New South Wales with no geographic points in common. This interconnector diversity increases the resilience of the grid against extreme climate conditions and improves overall system security.

In December 2019, AVP and Transgrid formally commenced this RIT-T through publishing a Project Specification Consultation Report (PSCR). This initial stage of the RIT-T process pre-dated the 'actionable ISP' process that is now part of the regulatory framework. The PSCR described the need for network and/or non-network investment in the western Victoria to southern New South Wales region, and the potential investment options to address this need. Submissions on the PSCR closed on 13 March 2020.

There has been a range of key developments since the PSCR was released, including:

- The implementation of the 'actionable ISP' framework in mid-2020.
- Updated assumptions and scenarios to be applied in the 2022 ISP being consulted on and finalised in July 2021, and subsequently amended through the 2021 *Inputs, Assumptions and Scenarios Report* (IASR) Addendum published by AEMO in December 2021.
- The development and commissioning of the Victorian Big Battery.
- Commitment by Transgrid (supported by underwriting by the Federal Government) in September 2021 to the Dinawan to Wagga Wagga portion of Project EnergyConnect being built at 500 kilovolts (kV) to lower the subsequent costs for expanding interconnection between Victoria and New South Wales.
- Federal Government underwriting of the New South Wales early works in April 2022.
- Additional early closures announced for coal power plants following the finalisation of the 2022 ISP assumptions.
- Continuing confirmation in the Draft (and final) 2022 ISP that VNI West remains on the optimal development path and should be progressed as a staged actionable ISP project.
- Elimination of some previously identified credible options from further RIT-T evaluation (such as the route in close proximity to Shepparton) through the 2022 ISP analysis.
- New scenarios and scenario weightings from the 2022 ISP, with the *Step Change* scenario being selected by stakeholders through a Delphi process as the most likely scenario.

These developments have had a material impact on the assessment under this RIT-T, with the project now projected to create greater benefits for consumers sooner.

While the PADR for this RIT-T was originally due to be published by 31 March 2021, AVP and Transgrid were given approval from the Australian Energy Regulator (AER) to extend the PADR publication date until 31 August 2022 given the substantive nature of developments since the PSCR[28]. This extension means the assessment in this PADR has been able to reflect the Draft 2022 ISP outcomes published in December 2021. While there have been some minor changes in assumptions between Draft and final 2022 ISP, the final 2022 ISP published 30 June 2022 has highlighted that the changes are not material to the VNI West business case (with no changes made to the timing or scope of the investment).

[28] See https://aemo.com.au/newsroom/news-updates/vni-west-cost-benefit-assessment-padr-extension. This follows an earlier extension granted by the AER in early March 2021 to extend the PADR publication date from 31 March 2021 until 10 December 2021.

This PADR is now being published in line with the actionable ISP framework and the direction by AEMO in the 2022 ISP, which has streamlined the RIT-T process (as outlined in Section 2.1).

1.2 Role of this report

This PADR continues the consultation process for this RIT-T, consistent with clauses 5.16A.4(c) – (h) of the National Electricity Rules (NER).

This report:

- Identifies and confirms the market benefits expected from expanding interconnection capacity between Victoria and New South Wales.
- Summarises points raised in submissions to the PSCR and highlights how these have been addressed in the RIT-T analysis[29].
- Describes the options being assessed under this RIT-T, which have been informed by submissions and also further analysis by AEMO in the 2020 ISP and the 2022 ISP.
- Presents the results of the net present value (NPV) analysis for each of the credible options assessed.
- Describes the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion.
- Identifies the preferred option at this stage of the RIT-T, that is, the option that is expected to maximise net market benefits in the long term interest of consumers.

Overall, a key purpose of this PADR, and the RIT-T more broadly, is to provide interested stakeholders the opportunity to review the analysis and assumptions, provide input to the process, and have certainty and confidence that the preferred option has been robustly identified as optimal. As jurisdictional planners, AVP and Transgrid are responsible for undertaking the RIT-T, and the AER monitors and enforces compliance with the process.

AVP and Transgrid are also releasing a supplementary report providing more detail on the wholesale market modelling undertaken to complement this PADR. Detailed cost benefit results are included as a spreadsheet appendix to this report.

1.3 Submissions and next steps

AVP and Transgrid welcome written submissions from stakeholders on the proposed preferred option presented, and the issues addressed in this PADR, including comments on the analysis, cost and ranking of the preferred option, the clarity of the project justification, and any other information available to assess social, cultural and environmental constraints at this early stage of the process.

Submissions are due on or before 9 September 2022, and should be emailed to VNIWestRITT@aemo.com.au.

A series of forums and briefings will be held prior to submissions closing, to provide stakeholders with a detailed understanding of the PADR and next steps. Information on the submission process (including how to make a

[29] Under NER 11.126.6, Transgrid and AVP are required to summarise and respond to points raised in the earlier PSCR.

submission) and upcoming stakeholder engagement activities will be published on the VNI West dedicated webpage on AEMO's website at https://aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission. If you do not want your submission to be publicly available, please clearly stipulate this at the time of lodgement.

The final step of the RIT-T process, the Project Assessment Conclusions Report (PACR), will include the matters outlined in this PADR and consideration of any submissions made in response to this PADR. The PACR is targeted for publication in late 2022.

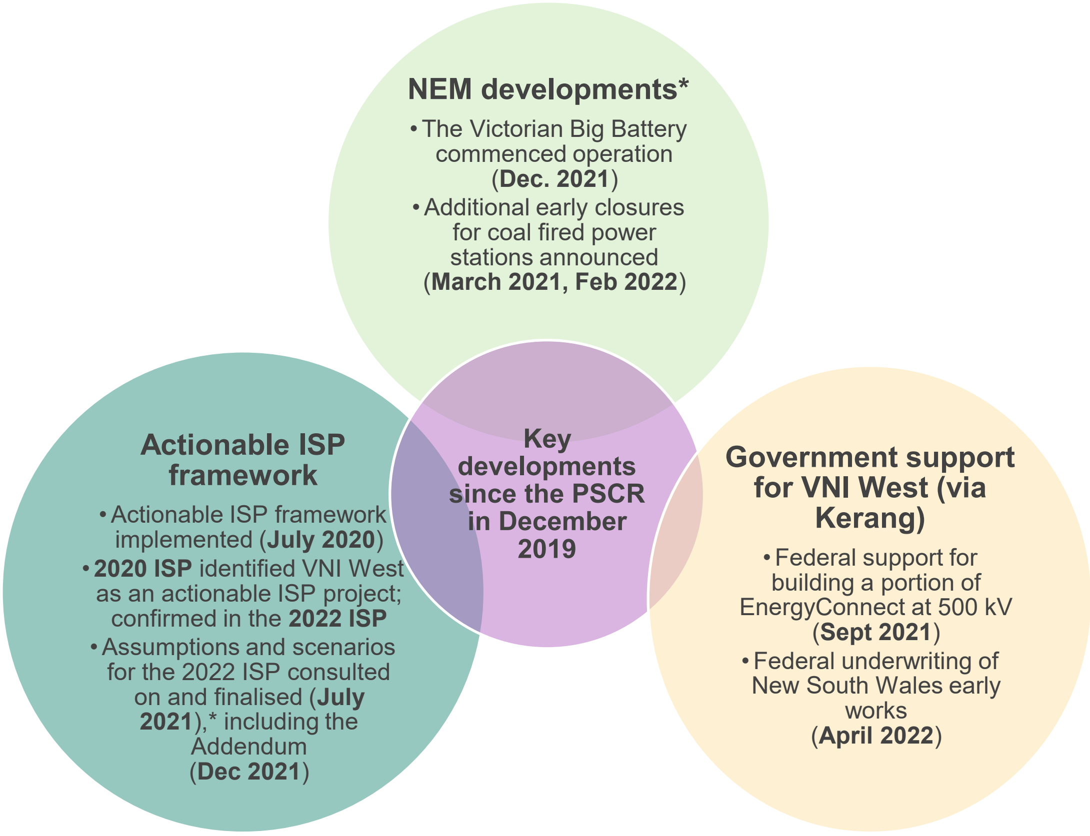
While the RIT-T is a technical and economic cost benefit test focused on delivering net market benefits, AVP and Transgrid acknowledge the important environmental, land-use, safety, amenity, social, cultural and community matters raised by stakeholders through this RIT-T consultation process. All stakeholders are welcome to provide feedback on any project-related matters, and any concerns raised that are not able to be addressed in the RIT-T process will be collated and addressed following completion of the PACR, should a project be justified through the RIT-T process. These matters will be given due consideration and addressed through community and stakeholder consultation as part of design and environmental and planning approvals processes, to avoid and minimise project impacts while ensuring the project continues to deliver market benefits in the long-term interest of electricity consumers.

2 Key developments since the PSCR

There have been a number of key developments since the PSCR was released in December 2019. The PADR has necessarily been delayed to enable each of these key developments to be appropriately reflected in the analysis and conclusions.

Figure 3 below highlights the key developments since the PSCR was released that have had a material impact on the assessment under this RIT-T.

Figure 3 Key developments since release of the PSCR



* There have also been other significant NEM developments since the PSCR that are captured in the July 2021 IASR and are reflected in this PADR assessment, but have not been separately listed in this figure.

In addition to the developments highlighted in Figure 3, there have been many significant NEM developments since the PSCR that are captured in the July 2021 IASR. These include the commitment of Project EnergyConnect, the introduction of the New South Wales Government's Energy Infrastructure Roadmap, various new renewable generation, storage and gas projects, and changes in demand outlook.

There have also been a number of status updates for generation and storage developments in the NEM since the PSCR was released.

AVP and Transgrid have drawn on the July 2021 IASR and the latest list of committed and anticipated projects from AEMO available at the time of finalising inputs for the PADR modelling, as outlined in Section 2.1 below.

2.1 Actionable ISP Framework implemented in mid-2020

On 1 July 2020, the new 'actionable ISP' rules[30] were introduced to the NER as part of a broader reform by the Energy Security Board (ESB) to streamline the transmission planning process. Under the new rules, the ISP provides a coordinated whole-of-system plan for the efficient development of the power system that meets power system needs in the long-term interests of consumers. The ISP identifies the major transmission investments (including enhanced interconnection) which are key to underpinning the energy transition (the 'optimal development path') and makes key projects 'actionable' by triggering a requirement to the relevant jurisdictional planners to prepare a PADR under the RIT-T.

As part of this framework, in August 2020 the AER published cost benefit analysis guidelines (CBA Guidelines) to make the ISP actionable in accordance with the new rules[31], which seek to minimise duplication between the ISP and RIT-Ts by implementing several new requirements. The CBA Guidelines are prescriptive in the assumptions and scenarios that should be used, stating that the default assumptions should be drawn from AEMO's most recent IASR, since they have been identified and developed through a robust consultation process with stakeholders[32]. The CBA Guidelines also allow the ISP to direct which options and scenarios are relevant to consider in the RIT-T application, which helps align the ISP and RIT-T and streamline the RIT-T process.

The RIT-T process for VNI West commenced prior to the introduction of the new actionable ISP framework and is subject to transitional provisions in the NER[33] and under the AER CBA Guidelines.

The transitional provisions allow AVP and Transgrid to elect to apply the new streamlined investment process/rules to this RIT-T at their discretion, as opposed to using the standard RIT-T process[34]. AVP and Transgrid have consequently opted to apply the new streamlined process to this RIT-T to facilitate the fastest possible delivery of the preferred option. A PSCR is not required for actionable ISP projects.

The transitional rules require that, where the transmission network service provider (TNSP) applies the new process, the PADR must address all submissions made by parties in response to the PSCR[35]. AVP and Transgrid therefore summarise and respond to all points raised in the earlier submissions to the PSCR in this PADR (see Section 4 and Appendix A4).

Further, the AER requires the assessment for this RIT-T to apply the new CBA Guidelines, since a PADR was not published ahead of the new guidelines[36].

The assessment in this PADR applies the assumptions from the 2021 IASR, finalised in July 2021, and relevant updates in the 2021 IASR Addendum published in December 2021, as well as the options and scenarios determined relevant by AEMO for VNI West in the 2022 ISP, as discussed further in Section 2.2.

---

[30] COAG Energy Council, Actionable ISP Rule change, March 2020, at http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/ESB%20Final%20Approved%20ESB%20Recommended%20National%20Electicity%20Amendment%20%28ISP%29%20Rule%202020.pdf.

[31] AER, Cost Benefit Analysis Guidelines, August 2020. At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[32] AER, *Cost Benefit Analysis Guidelines*, August 2020, p. 58

[33] NER clause 11.126.6.

[34] NER clause 11.126.5.

[35] NER clause 11.126.6.

[36] AER, *Guidelines to make the Integrated System Plan actionable*, Final Decision, August 2020, p. 19. At https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Guidelines%20to%20make%20the%20ISP%20actionable%20-%2025%20August%202020.pdf.

This PADR assessment also reflects the latest NEM generation information from AEMO available at the time of finalising the market modelling inputs (that is, the generation information released in February 2022), as well as the updated expected plant closure years released by AEMO in February 2022[37].

One of the factors leading to the deferral of publication of this PADR was aligning with the latest scenarios and assumptions in the 2021 IASR and the optimal development path in the Draft 2022 ISP, rather than basing the analysis on the previous 2020 IASR and 2020 ISP. By publishing after the final 2022 ISP, AVP and Transgrid have also been able to confirm that there have been no changes to the optimal development path between Draft and final ISP that would materially change the outcomes of this PADR assessment.

2.2 The 2020 ISP identified VNI West as an actionable ISP project and this was confirmed in the 2022 ISP

The 2020 ISP was released in July 2020 and confirmed the need for additional interconnection between Victoria and New South Wales. It declared VNI West an 'actionable ISP project' that is to proceed on a staged basis with decision rules and recommended that the most prudent option is to commence early works as soon as possible[38], with the overall project completed no later than 2027-28 (subject to decision rules being met)[39].

The 2022 ISP, released in June 2022, continued to identify VNI West as a staged actionable ISP project with the same 'identified need'[40] but without decision rules[41] and with updated investment timing from the 2022 ISP (see below) based on current views of earliest delivery if the project is progressed immediately.

The 2022 ISP highlighted that VNI West will increase access to Snowy 2.0's deep storages and other firming capacity, support new VRE (particularly in the Murray River and Western Victoria renewable energy zones [REZs]) needed to replace coal generation, provide greater system resilience to earlier than projected coal closures, secure fuel cost savings by needing less gas for generation, and reduce VRE curtailment by sharing geographically diverse VRE[42]. As part of the optimal development path, VNI West helps facilitate a reliable and secure energy sector transition to net-zero emissions while keeping energy prices as low as possible.

Following the release of the VNI West PSCR, the 2020 ISP narrowed the focus of the RIT-T for VNI West to two candidate options, namely:[43]

- A 500 kV high voltage alternating current (HVAC) double-circuit line from a new terminal station north of Ballarat to Wagga Wagga via Shepparton; and

[37] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[38] The early works are currently underway and have been supported through underwriting of the New South Wales components by the Federal Government announced in early April 2022 (as outlined in Section 2.5 below).

[39] The 2020 ISP recommended a timing of 2027-28, unless decision rules requiring pausing or cancellation were met. The three decision rules set out in the 2020 ISP that would result in VNI West being paused or cancelled were: (1) transmission costs, including any third-party contribution, exceeding $2.6 billion; (2) sufficient new market-based dispatchable capacity being in place in Victoria ahead of the next brown coal closure in Victoria; or (3) the *Slow Change* scenario unfolding, which included life extensions of existing coal-fired generation. See AEMO, 2020 ISP, July 2020, p. 82.

[40] The identified need is discussed in Section 3.

[41] As VNI West remains staged in the ISP and will have staged Contingent Project Applications, the ISP Feedback Loop arrangements now apply to protect consumers against risks of increasing project costs. The feedback loop assessment itself comprehensively tests alignment with the optimal development path, including by re-running the ISP modelling, if necessary, by considering multiple complex interactions that are unable to be captured within decision rules.

[42] AEMO, 2022 ISP, June 2022, p. 74.

[43] AEMO, 2020 ISP Appendix 3. Network Investments, July 2020, p. 37.

- A 500 kV HVAC double-circuit line from a new terminal station north of Ballarat to Wagga Wagga via Bendigo, Kerang and Dinawan.

The 2020 ISP provided analysis of a number of alternate network options that it concluded should be discounted and explicitly stated that the RIT-T is to exclude these options[44].

The 2020 ISP has now been superseded by the 2022 ISP, which considered a number of VNI West candidate network options, and identified a preferred option to be included in the optimal development path (the 500 kV HVAC double-circuit line going via new stations near Bendigo and near Kerang, called 'VNI West (via Kerang)'), while noting also that a non-network option is being assessed as part of this RIT-T[45].

The 2022 ISP also revised the scenarios required to be considered in the RIT-T analysis to the *Step Change* scenario, *Progressive Change* scenario, and *Hydrogen Superpower* scenario[46]. These scenarios, and the weights which the 2022 ISP requires to be applied to each, are discussed in Section 2.3 below.

The 2022 ISP outlines the two stages to VNI West:[47]

- Stage 1 is to carry out early works as soon as possible, for completion by approximately 2026.
- Stage 2 is to complete implementation of the project – a proposed 500 kV interconnector from a substation near Ballarat in Victoria to a new substation named Dinawan in South West New South Wales – by July 2031.

The 2022 ISP states that VNI West remains a staged actionable ISP project to be delivered as urgently as possible.

The cost benefit assessment in the 2022 ISP confirmed that staging the project is expected to result in an overall increase in expected weighted net market benefits of approximately $40 million, compared to not staging it[48]. This is because the benefits of being able to progress the project as soon as possible in the *Step Change* and *Hydrogen Superpower* scenarios (due to the early works having been completed) exceed the cost associated with incurring the early works component earlier than would otherwise be needed in the *Progressive Change* scenario.

Subject to meeting the feedback loop requirements, Stage 2 of the project is targeted for completion as soon as possible in two of the three scenarios considered in this PADR, with the commissioning dates assumed under each scenario aligned with the 2022 ISP [49]:

- 2030-31 under the *Hydrogen Superpower* scenario.
- 2031-32 under the *Step Change* scenario.
- 2038-39 under the *Progressive Change* scenario.

Stage 1 has the same assumed timing across all scenarios (progressing immediately for completion by approximately 2026)[50]. The early works may include project initiation, land-use planning, detailed engineering design, route development, biodiversity offset strategy, cost estimation, and strategic network investments, such

[44] AEMO, 2020 ISP Appendix 3. Network Investments, July 2020, pp. 37 and 66. The basis for discontinuing consideration of these alternative network options is summarised in Section 6.4 of this PADR.

[45] AEMO, 2022 ISP, June 2022, p. 75.

[46] AEMO, 2022 ISP, June 2022, p. 75.

[47] AEMO, 2022 ISP, June 2022, p. 74.

[48] AEMO, 2022 ISP Appendix 6, Cost Benefit Analysis, June 2022, p 61

[49] AEMO, 2022 ISP, June 2022, p. 80.

[50] AEMO, 2022 ISP, Appendix 5. Network investments, June 2022, p. 27.

as the enhancement of Project EnergyConnect[51]. Early works will provide an opportunity to engage with and consult community and stakeholders on a range of matters and help with route selection. The early works may identify cost savings, reduce cost uncertainties, and provide greater consumer confidence that they will not be over- or under-investing as part of VNI West.

For the New South Wales component, the early works are currently underway, supported via underwriting by the Federal Government announced in early April 2022 (as outlined in Section 2.5 below).

Full commissioning of the project by 2031 (in the most likely scenario) assumes a seamless transition from Stage 1 to Stage 2 following feedback loop confirmation, and approximately 12 months of inter-network testing following first energisation. Additional government support may allow this project to be completed earlier.

2.3 Consultation on, and finalisation of, updated assumptions and scenarios that were applied in the 2022 ISP

In July 2021, AEMO completed consultation on its latest IASR, which took into consideration feedback provided on the Draft IASR published in December 2020 as well as from several stakeholder workshops and webinars. The 2021 IASR reflects key industry changes since the 2020 ISP that are expected to have an impact on the benefits expected from increasing interconnection capacity between Victoria and New South Wales.

Through the IASR consultation, four ISP scenarios were developed, refined and included in the 2022 ISP showing a range of plausible futures for growth in electricity demand, and in decentralisation as business and household consumers manage their own energy.

The three scenarios identified as relevant for the RIT-T assessment for VNI West in the 2022 ISP are summarised by AEMO as follows:[52]

- *Progressive Change* scenario (previously *Net Zero 2050*) – pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time.
- *Step Change* scenario – rapid consumer-led transformation of the energy sector and co-ordinated economy-wide action to achieve net zero emissions by 2050.
- *Hydrogen Superpower* scenario – strong global action and significant technological breakthroughs with a near quadrupling of NEM energy consumption to support a hydrogen export industry.

As part of the 2022 ISP consultation process, the *Step Change* scenario was considered by energy industry stakeholders to be the most likely scenario to play out, ahead of the *Progressive Change* scenario[53].

As part of the 2022 ISP, AEMO deemed the fourth scenario in the 2021 IASR, the *Slow Change* scenario, not to be relevant for the RIT-T assessment of VNI West on account of its low likelihood (4%) and the optimal timing being found to be similar to the *Progressive Change* scenario[54].

[51] AEMO, 2022 ISP, June 2022, p. 75.

[52] For a full description of these scenarios, see AEMO, 2021 IASR, July 2021, p. 5.

[53] AEMO, Draft 2022 ISP, December 2021, p. 29.

[54] AEMO, 2022 ISP, June 2022, p. 75.

2.4 The Victorian Big Battery

In March 2020, the Victorian Parliament passed new legislation, the *National Electricity (Victoria) Amendment Act 2020* (NEVA), allowing the state to depart from the NER where needed to expedite necessary network investments. Under NEVA, the Victorian Energy Minister is able to exempt certain investments in new transmission infrastructure from the usual assessment tests, including the RIT-T.

In November 2020, the Victorian Minister for Energy, Environment and Climate Change made orders under the NEVA that directed AVP to enter into the System Integrity Protection Scheme (SIPS) Support Agreement to manage the procurement process to allow additional import of electricity over the existing VNI of up to 250 megawatts (MW) at peak times between November and March[55].

The Victorian Government subsequently utilised its powers under the NEVA to fast track AVP's procurement of the 'Victorian Big Battery' near Geelong to provide the SIPS service. The Victorian Big Battery is a 300 MW battery to enable increased import capacity of the existing VNI by 250 MW in peak demand periods[56]. AVP has contracted the battery to provide this 250 MW backup service from 1 November to 31 March each summer from 1 November 2021 to 31 March 2032[57].

The Victorian Big Battery has been reflected in the wholesale market modelling undertaken for this PADR (consistent with the 2022 ISP). Specifically, AVP and Transgrid have reflected its effect (increase) on transfer limits between New South Wales and Victoria while it provides the SIPS service for the five contracted months a year (until 31 March 2032)[58]. The Victorian Big Battery is assumed to be able to arbitrage to only a limited extent over these five months, but to be able to fully arbitrage for the remainder of the year outside of this contract period. At the end of the current SIPS contract on 31 March 2032, the battery is assumed to be able to freely arbitrage in the market (as any other large battery that is not contracted to provide network support would) and the transfer limits assumed in the base case are correspondingly lower.

2.5 Government support for VNI West early works

On 7 April 2022, it was announced that Transgrid has entered into a $75.8 million underwriting agreement with the Federal Government to enable Transgrid to commence community and stakeholder engagement, project planning and technical design for VNI West[59]. These activities form part of the New South Wales early works phase for VNI West.

While the early works for the New South Wales component are beginning now, the near-term focus is on completing the RIT-T, with the bulk of the early works in New South Wales planned to commence after completion of the RIT-T process.

55 See https://aemo.com.au/newsroom/media-release/victorian-battery-delivering-energy-reserves-in-summer.

56 See https://aemo.com.au/newsroom/media-release/victorian-battery-delivering-energy-reserves-in-summer.

57 See https://www.energycouncil.com.au/analysis/victoria-s-big-battery-what-exactly-is-it-for/.

58 The accompanying EY market modelling report provides additional detail regarding the impact on transfer limits from the Big Battery for both intra- and inter-regional network nodes.

59 See https://www.minister.industry.gov.au/ministers/taylor/media-releases/delivering-critical-energy-infrastructure.

2.6 Commitment to the Dinawan to Wagga Wagga portion of Project EnergyConnect being enhanced to be built at 500 kV

In September 2021, the Federal Government announced it had reached an agreement with Transgrid to enhance the capacity of the transmission network in south-western New South Wales. Under the agreement, the Federal Government is providing up to $181.5 million in underwriting support to enable the section of transmission lines being built from Dinawan to Wagga Wagga as part of Project EnergyConnect to be constructed at a larger capacity than originally planned[60]. As this is an underwriting, not a grant, the $181.5 million has been included as part of the capital cost of VNI West in this PADR (as outlined in Section 6.1, Figure 4) under 'Project EnergyConnect enhanced (incremental line build cost)' and depicted by the dashed portion on VNI West in Figure 4).

The agreement followed Transgrid revising the preferred route for Project EnergyConnect slightly as a result of design optimisation, whereby a new substation at Dinawan was included. The revised route now features a more direct path from Buronga to Wagga Wagga and no longer diverts via the existing Darlington Point substation, where new line entries are physically constrained.

The agreement enables the Dinawan to Wagga Wagga portion of Project EnergyConnect to be built to be operated at 500 kV when required, but initially operated at 330 kV (as originally planned). A key trigger for operation of this section at 500 kV would be the identification of a VNI West network option via Kerang as the preferred option for VNI West as part of this RIT-T, as this section of Project EnergyConnect now also forms part of that option.

Part of the rationale for enhancing this portion of Project EnergyConnect is that building a single line with larger capacity will save consumers hundreds of millions of dollars by removing the need for duplicate lines as part of the subsequent construction of VNI West, assuming the route via new stations near Bendigo and near Kerang is preferred and passes the RIT-T. In addition, delivery of a single line will minimise further disruption to landholders in the area and minimise the overall environmental impact[61].

The implications for this RIT-T are that the costs of this portion of the VNI West option assessed in this PADR have fallen since the PSCR. Specifically, while the original scope of the VNI West option included a new 500 kV line from Dinawan to Wagga Wagga, the new scope (and so cost) now only reflects the incremental cost involved with building the line at a higher capacity initially (that is, as a 500 kV line rather than a 330 kV line) and the subsequent costs associated with enabling the line to be operated at 500 kV rather than 330 kV.

The market modelling undertaken for this PADR assumes that the Dinawan to Wagga Wagga portion of Project EnergyConnect is built to 500 kV but operated at 330 kV under both the base case and the option cases, consistent with the approach taken in the 2022 ISP[62]. AVP and Transgrid consider that this has the effect of reducing the estimated market benefits for VNI West, since this assumption results in the base case already reflecting the additional transfer capacity associated with the line being built at 500 kV. The base case for this RIT-T (that is, if VNI West did not proceed) should more appropriately assume that this portion is built and

[60] See https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw.

[61] See https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw.

[62] AEMO, 2022 ISP, June 2022, p. 66.

operated at 330 kV,[63] as initially intended. Given that updating this base case assumption would increase the market benefits associated with VNI West, AVP and Transgrid do not consider this would have a material impact on the ranking of the options or the conclusion of this PADR assessment. It may, however, underestimate the benefits of the project for consumers.

2.7 Additional early closures announced for coal power plants

There have been a number of announcements made since the Draft 2022 ISP was released regarding the early closure of coal-fired power stations in the NEM. Specifically:

- AGL announced in February 2022 that the Loy Yang A Power Station in Victoria and Bayswater Power Station in New South Wales will close by at least 2045 and 2033, respectively (three years earlier than previously indicated)[64].
- Origin Energy submitted a notice to AEMO in February 2022 for the potential early retirement of Eraring Power Station in August 2025 (seven years earlier than previously indicated)[65].

The announcements are in addition to an earlier announcement by EnergyAustralia in March 2021 that the Yallourn Power Station in Victoria will close in mid-2028 (four years ahead of schedule)[66].

The wholesale market modelling undertaken as part of this PADR takes account of these updated dates (and draws directly on the February 2022 AEMO Generation Information publication). However, since the market modelling undertaken for this RIT-T (and the ISP) retires power stations according to a least-system-cost (including the consideration of carbon budgets where applicable) as opposed to at set dates, these announcements have only had a minor impact on the assessed net benefits of VNI West, as confirmed in the 2022 ISP. This is because the above dates effectively set the latest point at which the plants can retire, if the market modelling has not found it economic to do so earlier in the assessment period.

2.8 AER granted extensions for publishing this PADR

Under the 2020 ISP, this PADR was due to be published by 31 March 2021. However, in light of some of the key developments outlined above, AVP and Transgrid were granted an initial extension from the AER in early March 2021 to extend the PADR publication date until 10 December 2021.

Subsequently, and following a review of the updated IASR released in July 2021 and other key developments that occurred over 2021 (as outlined above), Transgrid and AVP identified the need to undertake more detailed market modelling as part of the PADR assessment. The time required to undertake this detailed modelling meant that a further extension was requested from the AER. In November 2021, the AER granted an extension for publishing

[63] Moreover, building the Dinawan to Wagga Wagga portion of Project EnergyConnect to 500 kV but operating it at 330 kV is expected to have a different impact on the wholesale market, compared to if it is built and operated to 330 kV.

[64] AGL Energy, *ASX and Media Release – 1H22 Results Announcement*, 10 February 2022, at https://cdn-api.markitdigital.com/apiman-gateway/ASX/asx-research/1.0/file/2924-02485194-2A1355883?access_token=83ff96335c2d45a094df02a206a39ff4.

[65] Origin Energy, *Media release – Origin proposes to accelerate exit from coal-fired generation*, 17 February 2022, at https://www.originenergy.com.au/about/investors-media/origin-proposes-to-accelerate-exit-from-coal-fired-generation/.

[66] EnergyAustralia, *Media release – EnergyAustralia powers ahead with energy transition*, 10 March 2021, at https://www.energyaustralia.com.au/about-us/media/news/energyaustralia-powers-ahead-energy-transition.

the PADR until 31 August 2022, which has allowed this PADR to align with the 2022 ISP optimal development path and has facilitated the detailed modelling undertaken for the RIT-T.

AVP and Transgrid consider these extensions to the PADR publication date to have been critical to facilitating a robust cost benefit assessment to determine the best outcome for energy consumers.

3 Benefits from VNI West

The driver for the two credible options considered in this PADR is to help facilitate the reliable and secure transition away from coal-fired generation to renewable generation while keeping costs to consumers as low as possible. The preferred option delivers over $687 million in expected net market benefit to consumers and producers of electricity and supports the energy market transition through:

- Efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in ageing generator reliability – including mitigation of the risk that existing plant closes earlier than expected.
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales through improved network capacity and access to demand centres.
- Enabling more efficient resource sharing between NEM regions.

These sources of market benefit were included as the 'identified need' for VNI West in the 2022 ISP.

The modelling in this PADR shows that, in the absence of investment under this RIT-T, significant alternative additional investment by market participants would be needed in the next 25 years to continue to meet demand and system stability and security requirements, as existing dispatchable generation (and in particular brown coal generation) in Victoria retires. It also shows that the proposed investment facilitates the development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales and, overall, enables more efficient resource sharing between NEM regions.

The modelling finds that VNI West unlocks significant transmission transfer capacity for the Murray River (V2) and Western Victorian (V3) REZs and that these REZs, in addition to the South-West New South Wales (N5) REZ, have considerably more renewable capacity built, compared to the 'do nothing' base case, in all three scenarios modelled. Specifically, with VNI West in place:

- The Murray River REZ is projected to build substantially higher solar capacity (between 2.3 gigawatts [GW] and 2.6 GW across the three scenarios).
- The Western Victoria REZ is projected to build a greater quantity of wind capacity (between 600 MW and 800 MW across the three scenarios).
- The South-West New South Wales REZ is projected to build more solar and wind capacity, particularly under the *Step Change* and *Progressive Change* scenarios (approximately 85 MW to 800 MW across the three scenarios).

The additional renewable capacity build, compared to the base case, is higher than the increase in REZ transmission limits facilitated by VNI West (shown in Section 6.1). This is because not all the generation will be operating at full capacity all of the time, and the modelling strikes a balance between small amounts of generation curtailment and efficient utilisation of REZ transmission capacity.

In addition, the modelling finds that the output from existing generators in both the Murray River and Western Victoria REZs is greater with VNI West on account of the transmission transfer capacity unlocked for these REZs. This means consumers can get access to more renewable generation that would otherwise be "spilled".

Overall, VNI West is found to support the development of additional renewable generation in western Victoria and southern New South Wales, as the NEM transitions to low-emission generation technologies. Opening up additional capacity in areas of the NEM for renewable generation investment facilitates geographical diversity in renewable generation and, when combined with stronger interconnection between regions, leads to less variability in aggregate output as a result of local weather effects.

Within the context of the RIT-T assessment, VNI West is expected to primarily deliver the following classes of market benefit[67]:

- Reduced generation investment costs, resulting from more efficient investment and retirement decisions.
- Reductions in total dispatch costs, by enabling lower cost renewable generation to displace higher cost fossil fuel generation.
- Avoided/lower intra-regional transmission investment associated with the development of REZs.

The modelling in this PADR shows that VNI West results in significantly lower costs to the market (and therefore ultimately to consumers), compared to the 'do nothing' base case.

Section 8 discusses each of the specific categories of market benefit under the RIT-T that have been estimated as part of the PADR assessment. Section 98.3 discusses in more detail the additional development and dispatch of renewable generation facilitated by VNI West under each scenario, as well as what it displaces/defers compared to the 'do nothing' base case.

This is a 'market benefit' RIT-T (as opposed to a 'reliability corrective action' RIT-T).

[67] While the RIT-T prescribes 10 different classes of market benefit that must be considered in a RIT-T assessment, AVP and Transgrid find that VNI West (via Kerang) is expected to primarily deliver these three classes of market benefit. Additional detail on each class of market benefit can be found in the AER's CBA Guidelines.

4 Consultation on the PSCR

Twenty-four submissions were received in response to the PSCR and each has been considered and responded to as part of this PADR. AVP and Transgrid also held a number of meetings with interested parties to further discuss the RIT-T assessment, which have played a pivotal role in the preparation of this PADR, including in relation to the consideration of a 'virtual transmission line' (VTL) non-network option.

In addition to the consultation undertaken to date, AVP and Transgrid will be undertaking a suite of RIT-T consultations following the release of this PADR, including two industry forums led by AVP and Transgrid prior to submissions closing.

4.1 Overview

The PSCR for this RIT-T was published in December 2019. On 24 February 2020, AVP and Transgrid held an industry forum on the PSCR that was attended by representatives from 35 organisations.

In total, 24 formal submissions were received in response to the PSCR, 20 of which have been published on AEMO's website (four submitters requested confidentiality)[68]. Table 2 below lists submitters to the PSCR.

Table 2 Submitters to the PSCR

Submitters to the PSCR	
AusNet Services	Mallee Regional Innovation Centre
Donald McGauchie	Murray River Group of Councils
Energy Users Associations of Australia (EUAA)	Neoen
EnergyAustralia	Origin Energy
ERM Power	Pacific Hydro
Fluence	Public Interest Advocacy Centre (PIAC)
Gannawarra Shire Council	Smart Wires
Hepburn Shire Council	Snowy Hydro
Hydro Tasmania	Star of the South
Major Energy Users (MEU)	TasNetworks

While submissions covered a range of topics, there were nine broad themes that were most commented on:

- Scope of the options included in the assessment.
- Support for an accelerated delivery of the preferred option.
- Consideration of non-network options.
- Interaction with other major transmission investments.

[68] See https://aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission/stakeholder-consultation.

- Accuracy of the option cost estimates.
- Interaction with the Victorian Big Battery.
- Comments on costs and benefits captured in the assessment.
- Comments on the identified need and the amount of increased transfer capacity.
- Social impacts and network topology considerations.

In addition, before and after receiving submissions, AVP and Transgrid held bilateral meetings with interested parties to further discuss the RIT-T assessment. These have played a pivotal role in being able to define and undertake the assessment in this PADR, including in relation to the consideration of non-network options.

The key matters raised in non-confidential submissions and stakeholder feedback sessions relevant to the RIT-T assessment are summarised in the following subsections. Also below are AVP and Transgrid's responses to the themes raised in submissions, with an explanation as to how these matters have been reflected in the PADR assessment.

Appendix A4 provides a full summary of all non-confidential points raised as part of consultation on the PSCR, many of which remain relevant, notwithstanding the time that has passed since submissions were received and subsequent additional ISP analysis.

Some matters raised were not directly relevant to this RIT-T phase but will be considered in subsequent phases if the RIT-T is successful.

4.2 Scope of the network options

A number of submissions commented on the network options considered in the RIT-T analysis. As highlighted in Section 2, the network options for additional interconnection between Victoria and New South Wales have been further considered by AEMO as part of its preparation of the 2020 ISP and the 2022 ISP, with the consequence that this RIT-T is now recommended by the ISP to focus on a single network option (VNI West (via Kerang)), which is a refinement of the 'VNI 7' option in the PSCR. Notwithstanding, AVP and Transgrid summarise below submissions received from stakeholders on the scope of the network options.

Several submissions commented on the VNI 6 option in the PSCR, which was an interconnector on new corridors (via Bendigo or Shepparton). AusNet Services suggested that a variation of the 2020 ISP VNI 6 topology that would connect into the 500 kV network at a new terminal station site north of Melbourne should be investigated (and South Morang was proposed as the new terminal station site). AusNet Services stated that this option could be delivered more quickly due to fewer outage constraints and availability of existing land and easements that currently form part of AusNet Services strategic land holdings[69].

EnergyAustralia suggested that the REZ extension from Buronga to Red Cliffs for VNI 6 should be considered[70].

The VNI 6 option put forward in the PSCR and included in the 2020 ISP was ruled out in the 2022 ISP, as outlined in Section 6.4 below, as it did not optimise benefits for consumers. It is therefore not considered in this RIT-T.

AusNet Services stated that the Victorian transmission system currently has multiple issues that require resolution, including system strength and stability issues, the need for additional network capacity to enable new

[69] AusNet Services, p 2.

[70] EnergyAustralia, p 2.

generation connections, and the need for development of future REZs. AusNet Services considers that selection of the most efficient solution to the primary need of supply reliability should be made while complementary solutions to other issues are considered in parallel through processes focused on these separate issues[71].

As outlined in Section 2.1, this RIT-T adheres to the actionable ISP framework and so seeks to address the identified need as set out in the 2022 ISP[72]. The identified need covers three key sources of market benefits, including reliability in Victoria, as set out in Section 2.2. Moreover, AVP and Transgrid consider that VNI West (via new stations near Bendigo and near Kerang) is a more efficient way of meeting all three components of the identified need, compared to considering each in a piecemeal manner.

A range of parties queried whether the network options can be staged. Suggested options for staging included:

- Staging single-circuit options to reduce overall costs to consumers[73].
- Staging to achieve the near-term requirements for increased transmission network transfer between the Victorian and New South Wales regions first but also include the flexibility to add additional capacity at a later date, if required[74].
- Portions of the scope being developed sequentially, for example, the Ballarat to Bendigo to Kerang portion initially[75].
- Better scoping and sequencing of VNI 7 (an earlier variant of VNI West (via Kerang)), such as early thermal and structural capacity upgrade to the Kerang to Bendigo 220 kV line, could unlock substantial additional solar power generation in the very short term[76].

The possibility of staging capacity for VNI West by building to 500 kV but initially operating at 330 kV, or by stringing only one side of the double-circuit line initially, was considered but not progressed in the course of preparing this PADR. The cost of this staged option is nearly the same as for the full VNI West option, due to easement requirements and, in the case of operating at 330 kV initially, the cost of having to introduce new 330 kV terminal stations. Staging of option capacity would also introduce uncertainty as to the required voltage of connection assets for parties seeking network connections. Staging VNI West in this way is therefore not considered to be a credible option.

Developing portions of the scope sequentially (for example, building the Ballarat to Bendigo to Kerang portion initially) or changing the scope as suggested in submissions (for example, upgrading the Kerang to Bendigo 220 kV line first) are not considered able to meet the identified need as set out in the 2022 ISP. For example, while they both may marginally add to Victoria's reliability, they would not materially facilitate the efficient development and dispatch of generation in southern New South Wales, nor materially enable more efficient resource sharing between NEM regions.

Smart Wires proposed that modular power flow control (MPFC) equipment should be considered as part of the options analysis[77]. As part of preparing this PADR, AVP and Transgrid have tested the technical feasibility of a range of power flow control solutions, as an alternate to phase-shifting transformers or traditional reactive

[71] AusNet Services p 1.
[72] In accordance with NER 5.16A.4(d)(2).
[73] EnergyAustralia, p 1.
[74] ERM Power pp 2, 4.
[75] Pacific Hydro, pp 1-2.
[76] Donald McGauchie p 3.
[77] Smart Wires, p 3.

compensation solutions, as part of VNI West. The outcome of this analysis is that the specification of VNI West in this PADR includes power flow technology as part of its scope, reflecting the proposal from Smart Wires in response to the PSCR. AVP and Transgrid note that procurement of a power flow control solution is expected to be via a contestable process following completion of the RIT-T assessment.

4.3 Support for an accelerated delivery of the preferred option

A range of submitters expressed support for an accelerated timeline for expanding interconnection capacity between Victoria and New South Wales[78].

AVP and Transgrid note that AEMO assessed the timing for VNI West as part of the ISP process (subject to assumed lead times provided by AVP and Transgrid) under the least-cost development path (assuming perfect foresight) for each scenario as follows[79]:

- 2030-31 under the *Hydrogen Superpower* scenario.
- 2031-32 under the *Step Change* scenario.
- 2038-39 under the *Progressive Change* scenario.

The 2022 ISP called for VNI West, along with all actionable projects, to be progressed as urgently as possible to provide valuable insurance against faster-than-expected coal closures or slower-than-expected VRE and storage development[80]. The 2022 ISP also noted the importance of allowing sufficient time for community co-design of project implementation and flexibility in the procurement of expertise, materials and equipment,

For the *Hydrogen Superpower* scenario and *Step Change* scenario, these timings are effectively the earliest timings possible under the current planning processes. With support, it may be possible to construct the project earlier and AVP and Transgrid are actively exploring ways to do so. The benefits of earlier commissioning have not been assessed in the ISP or this PADR given that any further acceleration of delivery would require additional support outside the current regulatory and planning processes.

4.4 Consideration of non-network options

The PSCR sought submissions from providers of potential non-network solutions for information on options that may be capable of addressing or partially addressing the identified need.

Transgrid and AVP received two submissions from proponents of potential VTL capabilities, both of whom requested confidentiality. AVP and Transgrid engaged with these submitters to discuss the options proposed. Following the extension of the PADR publication date, Transgrid and AVP sought confirmation from these potential proponents that they remained interested in providing a non-network solution as part of this investment.

Informed by this feedback, a non-network VTL has been included as a component of a second credible option in the PADR assessment, combined with VNI West, as outlined in Section 5. Consideration of a non-network component in this RIT-T is supported in the 2022 ISP.

[78] AusNet Services p 3, Hydro Tasmania p 3, Murray River Group of Councils, p 5, Pacific Hydro, p 1 & Snowy Hydro, p 2.

[79] AEMO, 2022 ISP, June 2022, p. 80.

[80] AEMO, 2022 ISP, June 2022, p. 12.

The VTL considered consists of two new batteries (one at South Morang in Victoria and one at Sydney West in New South Wales) that will receive signals from relevant locations of the network. The specific locations for the batteries differ from those proposed by the proponents and are based on further detailed analysis undertaken by Transgrid and AVP.

As outlined in Section 6.3, the VTL solution is not considered capable of forming a credible standalone option, since it cannot meet all elements of the identified need (as outlined in Section 6.3.3). Consequently, a VTL solution has been assessed as an additional component that could be put in place to improve transfer capacity ahead of investment in the network (which remains VNI West), to test if it is expected to provide additional net benefits.

To be effective, the VTL component is expected to require a response time of within 200 milliseconds (ms) for the battery component and the protection and control systems, including for the communications component. Significant additional work would be required to comprehensively determine technical feasibility. However, to determine whether it is likely to form part of the overall preferred option, for the purposes of the PADR the VTL component is assumed to be technically feasible.

AVP and Transgrid have considered the VTL component as a generic option for costing purposes at this stage of the RIT-T, although informed by discussions with submitters. A separate, competitive procurement process will be undertaken if the VTL component is considered to form part of the ultimately preferred option at the conclusion of this RIT-T.

4.5 Interaction with other major transmission investments

A number of submitters suggested that the PADR should investigate the impact on the RIT-T assessment where other major transmission projects do not proceed, or proceed in a different form to that assumed[81].

In line with the CBA Guidelines, the modelling in this PADR reflects the other actionable ISP projects and major transmission projects in the ISP optimal development path (based on the Draft 2022 ISP, which was not materially different from the final 2022 ISP)[82]. Section 8 provides a detailed description of the methodology used to estimate the market benefits associated with the credible options, including the treatment of committed, actionable ISP projects, future ISP projects and ISP development opportunities from the 2022 ISP optimal development path.

AVP and Transgrid also note that comments in some submissions referenced the fact that, at the time, some of these other major transmission projects were still in the process of completing a RIT-T/regulatory review (for example, HumeLink, VNI Minor, Marinus Link and Queensland – New South Wales Interconnector (QNI) Minor). All these projects have now completed the RIT-T and, in the case of VNI Minor and QNI Minor, have received regulatory approval of the associated contingent project application (CPA) from the AER (where relevant). Even if regulatory approval had not yet been received for these projects, inclusion of these projects in all PADR analysis is a requirement of the CBA Guidelines, unless a ‘demonstrable reason’ can be provided for not including them.

[81] MEU p 5, PIAC, pp 1-2, TasNetworks p 2, ERM Power pp 3-4 and Origin, p 2.

[82] Refer to Table 6 for the modelled timing of the other major transmission projects in this RIT-T compared with the Draft and final 2022 ISP timings.

4.6 Accuracy of the option cost estimates

A number of submitters requested additional detail on how the costs of the options in the RIT-T assessment had been estimated, with some suggesting that the capital cost should be estimated to a level of +/- 20% in the PADR[83].

Significant work has been undertaken since the PSCR to develop more accurate cost estimates for the options included in this PADR assessment, including in light of the various social impacts and network topology considerations (as raised in submissions and discussed below). The cost estimates presented in this PADR have been undertaken on a jurisdictional basis, with AVP responsible for the estimates of the part of the options located in Victoria and Transgrid responsible for the estimates of the part of the options located in New South Wales. In both cases, the revised cost estimates are considered to have an accuracy of +/- 30%[84], which AVP and Transgrid consider to be 'class 4' estimates and in line with the level of accuracy typical at this stage of the investment process[85].

Section 8.1 outlines how the cost estimates have been updated since the PADR, including being broken out into key cost categories. Appendix A3 provides additional detail in response to submissions on the cost estimating methodologies applied for each of the key categories of costs (for both the Victoria and New South Wales components).

EUAA proposed that the ultimate cost presented in the PACR should be estimated to within a +/- 5% level of accuracy and that[86]:

- This should form the cap of any subsequent contingent project application to the AER.
- The PACR contain letters from AVP and Transgrid undertaking that they are prepared to build their portion of the preferred option at no higher cost than the respective agreed caps.
- RIT-T proponents should undertake detailed stakeholder consultation on the methodology to be used to develop these estimates as part of the PADR, similar in style and content to that which AEMO has undertaken for other major ISP assumptions and methodology.

Transgrid and AVP note that there are already 'check points' built into the actionable ISP process to confirm that the project remains in the optimal development path if the estimate of project costs increases materially.

As part of the contingent project process, Transgrid will seek a 'feedback loop' confirmation from AEMO in line with the new actionable ISP framework ahead of lodging a CPA for investment in VNI West. As with HumeLink, Transgrid is intending to submit two CPAs to the AER in relation to the regulatory cost recovery for the project:

- The 'Initial CPA' will seek cost recovery for the Stage 1 works, based on the preferred option.
- The 'Final CPA' will seek cost recovery for the Stage 2 implementation costs, including the construction costs of the project (this CPA will cover the bulk of the project cost). Transgrid will need to seek further 'feedback loop' confirmation from AEMO prior to submitting the 'Final CPA' to confirm that the project is still part of the optimal development path in the latest ISP and delivers positive market benefits in the 'most likely' scenario.

[83] EUAA p 3-4, ERM Power p 3, MEU p 7.

[84] Accuracy bands have been derived statistically, such that 80% of project estimates should fall within these limits. It is therefore expected that, across a large sample of projects, approximately 20% of them will fall outside of these bands.

[85] AEMO, *2021 Transmission Cost Report,* August 2021, p. 12. At https://aemo.com.au/-/media/files/major-publications/isp/2021/transmission-cost-report.pdf?la=en.

[86] EUAA p 3.

An ISP feedback loop requires AEMO (in its national planning role) to confirm that the preferred option from the RIT-T remains aligned with the optimal development path in the most recent ISP. In performing the feedback loop, AEMO will consider both the New South Wales and Victorian components of the project as a whole to confirm that the investment still optimises benefits for consumers. This process will ensure that the investment is confirmed as being consistent with the optimal development path in the latest ISP, where any costs have increased.

AVP and Transgrid also note that, while Stage 1 of the preferred option is designed to ensure the project can be delivered by its earliest estimated commissioning date (July 2031) consistent with when the project is needed in the most likely ISP scenario, the early works activities involved will also enable the development of a more detailed cost estimate for Stage 2 as part of this process[87]. Indeed, the scope for early works to reduce cost uncertainties, and provide greater consumer confidence that they will not be over- or under-investing in this key project, is explicitly noted in the 2022 ISP[88].

For the Victorian component of the ultimately preferred option, it is currently anticipated that AVP will seek competitive provision through the contestable arrangements applying in Victoria. The costs will therefore be determined by the competitive market outcome.

These measures together ensure that the preferred option only proceeds where it is expected to be net beneficial to consumers.

4.7 Interaction with the Victorian Big Battery

Some submitters requested further information regarding the interaction between the Victorian Big Battery, announced after the PSCR and designed to deliver a 250 MW network support SIPS service in Victoria, and the identified need for this RIT-T[89].

As outlined in Section 2.4, the Victorian Big Battery (located at Moorabool Terminal Station) has been reflected in the wholesale market modelling undertaken for this PADR. Specifically, AVP and Transgrid have reflected its effect (increase) on transfer limits between New South Wales and Victoria while it provides the SIPS service for the five contracted months a year (until 31 March 2032)[90]. The Victorian Big Battery is assumed to be able to arbitrage to only a limited extent over these five months, based on any available capacity beyond its contracted capacity, but to be able to fully arbitrage for the remainder of the year outside of this contract period. At the end of the current SIPS contract on 31 March 2032, the battery is assumed to be able to freely arbitrage in the market (as any other large battery that is not contracted to provide network support would), and the transfer limits in the base case are correspondingly lower.

The operation of the Victorian Big Battery has also been taken into account in modelling the further impact on transfer limits that could be achieved by the VTL component of the second option considered in this PADR. Both options net market benefits are over and above that provided by the VBB.

[87] The early works as part of Stage 1 include project initiation, stakeholder engagement, land-use planning, detailed engineering design, cost estimation and strategic network investments. See AEMO, 2022 ISP, June 2022, p. 75.

[88] While this point was not explicitly made in the Final 2022 ISP, it was in the Draft 2022 ISP (see p. 12).

[89] PIAC, pp 1-2, Origin, p 2 & MEU p 5.

[90] The accompanying EY market modelling report provides additional detail regarding the impact on transfer limits from the Big Battery for both intra- and inter-regional network nodes.

4.8 Comments on costs and benefits captured in the analysis

EnergyAustralia commented that the network options may lead to an increase in the need for Frequency Control Ancillary Services (FCAS) and Network Support Control Ancillary Services (NSCAS), considering the proportional change away from dispatchable to non-dispatchable capacity because of the project[91].

While the two options assessed support the NEM transition from dispatchable to non-dispatchable capacity and therefore indirectly may affect the level of FCAS and NSCAS, the *difference* between the options is not expected to be material since the options only differ by the VTL component (which is not expected to result in lower FCAS or NSCAS commensurate with the difference in the weighted net benefits of the two options).

Moreover, the wholesale market modelling undertaken for this PADR finds that there is expected to be a relatively small reduction in the capacity available in the NEM to provide ancillary services by the end of the assessment period with VNI West, in place, compared to the base case, for each scenario. Specifically, the modelling finds that the amount of dispatchable capacity forecast in the NEM by the end of the assessment period falls by between 2.1% and 4.7%, depending on the scenario modelled, with VNI West in place, compared to the base case.

AVP and Transgrid have therefore not modelled the impact on FCAS or NSCAS as part of the PADR.

MEU stated that the improvement in reliability that will occur by having VNI West separated from the existing VNI easement, and what this improved reliability will do to the reliability seen by consumers, should be included in the assessment[92].

While AVP and Transgrid agree with MEU that having VNI West geographically separated from the existing VNI easement will lead to a greater level of reliability (for example, through minimising the impact of events such as lightning strikes, bushfires or extreme wind events), AVP and Transgrid have not modelled this as part of the PADR assessment. The reliability benefits from avoiding such 'high impact low probability' events affecting multiple lines simultaneously are difficult to estimate and, in the context of the PADR assessment, are unique to VNI West and so have no bearing on the identification of the preferred option (since VNI West forms part of both options being assessed). These benefits would improve the business case of either credible option relative to the base case.

Origin commented that all necessary augmentation of both Victorian and New South Wales networks for increased interregional transfer should be included in the costs for all options (for example, if any options also require intra-regional upgrades in order to alleviate congestion caused by the new transfer capacity or to unlock the full benefits of augmentation)[93].

The market benefits estimated in this PADR reflect a continuation of any current intra-regional constraints (unless projects to alleviate these constraints are identified as actionable or future ISP projects). This is typical for RIT-Ts under the new actionable ISP framework, which focus on addressing a particular identified need, being cognisant of future developments that are also going to be needed to enable the transition. Any other actionable or future ISP projects unrelated to the identified need in this RIT-T are included in both the base case and the option assessments and therefore do not contribute to the net benefits for VNI West. These other ISP projects would be subject to a separate RIT-T assessment (assuming they meet the requirements for a RIT-T to be applied).

[91] EnergyAustralia p 2.

[92] MEU p 9.

[93] Origin, p 3.

4.9 Comments on the identified need and the amount of increased transfer capacity

EUAA stated that it is not clear what amount of increased interconnection capacity is required to satisfy the identified need, nor why the particular options to be examined in detail in the PADR were chosen[94]. MEU submitted that an assessment as to the level of transfer capability that is being sought by the augmentation is absent from the identified need and, without identifying what transfer capacity is needed by consumers (in terms of MW flow north and south), it is difficult to see how the option that best meets the needs of consumers will be identified[95].

This RIT-T is being undertaken in accordance with the actionable ISP framework[96]. Under this framework, the ISP establishes the identified need and considers a range of options for each network need as part of developing the optimal development path across the NEM. The role of the RIT-T is to identify the most efficient way to meet the need by extending and refining the ISP analysis, rather than duplicating the ISP analysis. The options assessed in this PADR, and the associated increases in transfer capacity, are therefore consistent with those recommended in the 2022 ISP.

The RIT-T process is not seeking to replicate the ISP process or to more closely specify the identified need in terms of an increase in transfer capability required from options. However, from the analysis completed to date, AVP and Transgrid consider that the increase in transfer capability required from credible options needs to be substantive to meet all three elements of the identified need in the 2022 ISP.

AusNet Services considered that the 'identified need' description could be improved by providing a clear description of the relativity and quantum of benefits provided by each driver. AusNet Services said it understood that most of the project benefits relate to maintaining Victorian supply reliability and stated that, if this is the case, the efficient solutions should be considered in this context[97].

While this PADR separately quantifies and comments on the key sources of estimated market benefit, consistent with the categories stipulated in the RIT-T, it does not attribute them to the three limbs of the identified need. AVP and Transgrid note that the three limbs of the identified need are inter-related and attempting to apportion the estimated benefits to individual limbs of the identified need would require a range of subjective assumptions to be made.

4.10 Social impacts and network topology considerations

A number of submitters raised social impacts and concerns with topologies running through north-eastern Victoria (for example, VNI 6 in the PSCR). Submitters commented that this topology runs through high value agricultural farmland including a high concentration of irrigation infrastructure investment and related agricultural production (in a region that has already demonstrated local concerns regarding planning approval). This would likely impact timing and cost of construction as well as limiting development of new renewable generation in the area[98]. It was

[94] EUAA p 2.

[95] MEU, pp 8-9.

[96] AER, *Guidelines to make the Integrated System Plan actionable*, Final decision, August 2020. At https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Guidelines%20to%20make%20the%20ISP%20actionable%20-%2025%20August%202020.pdf.

[97] AusNet Services p 1.

[98] Donald McGauchie, p 3, MRGC, p 4 & Pacific Hydro, p 3.

suggested by five submitters that VNI 7 (an earlier variant of VNI West (via Kerang)) had a preferable topology and the submitters believed that it would receive more community support[99].

AVP and Transgrid note that the VNI 6 option put forward in the PSCR and the 2020 ISP has been ruled out in the 2022 ISP, as it does not optimise benefits for consumers when compared to the VNI West (via Kerang) alternative. The 2022 ISP found that the VNI West (via Kerang) alternative provided higher market benefits than VNI 6 (via Shepparton) due to having access to the better renewable resource in Murray River REZ compared to Central North Victoria REZ, as well as the additional hosting capacity being greater in magnitude. This is explained further in Section 6.5 below. The VNI 6 option is therefore no longer being considered in this RIT-T. The VNI West option assessed in this PADR is a refinement of the earlier VNI 7 option, which was seen by stakeholders as being preferable in terms of network topology and community support.

It was also suggested by a submitter that an assessment should be considered in relation to the feasibility of actually obtaining access to land and easements required for each option, along with requirements for approvals, consents and impact assessment[100].

Transgrid and AVP agree that consideration of social impacts and land use should be taken into account in this PADR, to the extent possible at this early stage of the process and recognising that this is a key concern across a range of stakeholders in relation to the assessment of major transmission projects. Section 5 provides additional detail on how social and environmental issues have been considered as part of this PADR.

[99] Donald McGauchie p 3, MRIC, p 12, MRGC, pp 3-4, Gannawarra Shire Council, pp 1-2 & Pacific Hydro p 3.

[100] AusNet Services p 3.

5 Social and environmental considerations

Social and environmental concerns are key considerations for a range of stakeholders in the assessment of major transmission projects. These have been taken into account as part of the RIT-T, to the extent possible at this stage of the process. Work continues in parallel to this process to understand how best to address any concerns and create opportunities for regional communities to benefit from VNI West, should the RIT-T be successful.

5.1 Social considerations

Transgrid and AVP recognise the importance of early engagement with regional communities, Traditional Owners and landholders to understand potential social impacts associated with building this linear infrastructure. AVP and Transgrid will seek to engage with a range of key stakeholders on the PADR to ensure the rationale for, and benefits of, the project are clearly understood, and to facilitate early community and Traditional Owner input on potential social and cultural considerations of the preferred proposed option at this stage. This input will be cross-referenced with the findings of the desktop study (discussed below), used (if applicable) to help inform the PACR, and retained for use in the delivery of the project.

The PACR will include a summary of all consultation undertaken, unless shared on a confidential basis.

The RIT-T is not a route selection process. If a project is confirmed through the RIT-T process, the development of a project route and the location of any proposed terminal stations will be determined through a rigorous route and site selection process, detailed design, and community consultation and engagement. The proposed route and associated infrastructure would also be subject to the requirements of relevant planning and environmental approval processes.

5.1.1 Community involvement

AVP and Transgrid recognise the vital role that community and landholders have in the planning and delivery of major transmission infrastructure projects. AVP and Transgrid acknowledge that, while the community is generally supportive of renewables and a transition away from coal at lowest cost for all consumers, stakeholders who live closer to where transmission lines and associated infrastructure may be constructed are likely to have different perspectives or concerns about the potential impacts, and may not feel that the benefits outweigh the impacts.

Best practice says that early engagement based on the values of trust, integrity, empathy and transparency is fundamental to building understanding and the foundation for support. This includes ensuring that stakeholders', communities' and landholders' points of views are sought, acknowledged and appropriately considered and responded to in a respectful, fair and equitable way as early as possible. This will enable people living and working nearby to have the opportunity to participate in shaping an outcome that is socially acceptable for regional communities while meeting consumer needs.

5.1.2 Lessons learnt from previous projects

Transgrid and AVP are dedicated to continuously improving their engagement practices.

Transgrid has recently conducted a review of the engagement processes used in previous projects to better understand the experience of impacted landholders and communities and determine improvements for future project consultation. AVP has also reflected on points of view from multiple stakeholder perspectives and lessons learned through the Western Renewables Link community and landholder engagement and other comparable projects. Recommendations from the reviews will be taken into consideration in the development of Community and Stakeholder Engagement Plans for this VNI West project.

In particular, the following themes have been identified as critical to building awareness and support, and are a key priority for this project:

- A commitment to early engagement, listening to and communicating with stakeholders with honesty and integrity to understand their views and concerns, and ensuring the project team is equipped to have these conversations.
- Co-designing and clearly communicating the engagement process and opportunities to stakeholders including landholders and communities – including how and when to provide feedback, and how their feedback will be used.
- Ensuring all interested stakeholders and communities can easily access project information through a variety of channels including websites and other platforms, and that any information can be easily understood.
- Providing ample notice of consultation or engagement opportunities, and ensuring educational materials are available to help increase energy literacy, to facilitate meaningful participation.
- Dispelling myths in a timely manner to help alleviate undue anxiety.

To allow for potential remediation of unknown geological, environmental and social concerns, the cost estimates presented in this PADR include an approximate additional $300 million of cost contingency, added to the Victorian component of the estimate[101], compared to the VNI West cost estimate presented in the 2022 ISP. While AVP and Transgrid will not know specific details until route planning commences, this cost contingency has been added to AVP's Victorian estimate in recognition that, based on recent experience, some level of route diversion, tower redesign, or screening may be required beyond that included in the estimate of the Victorian component of the project presented in 2022 ISP. This cost contingency provision does not anticipate undergrounding costs. If partial undergrounding was to be required, a greater level of contingency would be needed.

5.1.3 Approach to community and stakeholder engagement

AVP and Transgrid are committed to working with local communities with honesty and integrity in a meaningful, responsive and equitable way, through transparent and inclusive practices, and seek to minimise the social, environmental and cultural impacts of our projects and operations. Both organisations will do this by engaging with our communities to understand what matters most, and to build trust and positive relationships.

AVP and Transgrid's approach to community and stakeholder engagement is based on best practice principles and the International Association of Public Participation (IAP2) Spectrum of Public Participation – an internationally recognised tool for planning public participation in major projects.

[101] The ISP cost estimates already included a contingency cost for New South Wales works.

This approach takes into consideration guidance from industry – including the Clean Energy Council's *Community Engagement Guidelines for Building Powerlines*[102], the Energy Charter's *Better Practice Landholder and Community Engagement Guide*, and the 2021 AER '*Guidance Note: Regulation of actionable ISP projects*'[103], which states that there is a clear expectation for TNSPs to carry out high quality, early engagement with local community and consumer representatives, which may result in:

- Improved stakeholder and community understanding of the project's costs and risks.
- Opportunities for the project solution to be designed with input from the local communities impacted by the proposed major transmission project.
- TNSPs having a better understanding of community concerns about route selection, which in turn would help the TNSP manage the associated risks.
- Opportunities for the TNSP to address and manage concerns raised by stakeholders.

The proposed project will also draw on the relevant recommendations contained in the Australian Energy Infrastructure Commissioner's 2021 Annual Report (and subsequent reports) in helping guide the project's approach to the implementation of landholder community relations programs[104].

Early engagement

As part of our commitment to engage stakeholders from the very early stages of project development, AVP and Transgrid are already engaging with a range of stakeholders including consumer groups and community representatives to provide information about the project and encourage participation in the VNI West RIT-T process. The specific objectives of this early engagement are to:

- Help stakeholders understand the need for, and benefits of, VNI West and the steps involved in project development.
- Develop best practice engagement by seeking early stakeholder feedback and guidance on the proposed engagement approach.
- Deepen the project team's timely understanding of the VNI West project area, in particular environmental, community and local industry considerations, through early engagement with representative groups.
- Promote meaningful and timely stakeholder input into the project's cost-benefit (RIT-T) assessment while gaining an understanding of key stakeholder issues that may not sit within the RIT-T framework.

We commit to doing this while being respectful that many stakeholders have limited resources and competing time commitments.

Before publication of the PADR, AVP and Transgrid have engaged with key stakeholders in Victoria and New South Wales respectively through MP briefings, local council briefings, consumer forums, stakeholder roundtables and briefings and project updates. This includes discussions with a number of councils at this early stage, including Campaspe, Edward River, Federation, Gannawarra, Greater Bendigo, Hepburn, Lockhart, Loddon,

[102] Clean Energy Council: *Building Powerlines for Renewable Energy Developments*, December 2018, at https://www.cleanenergycouncil.org.au/advocacy-initiatives/community-engagement/community-engagement-guidelines-for-building-powerlines-for-renewable-energy-developments.

[103] At https://www.aer.gov.au/system/files/AER%20-%20Final%20Guidance%20note%20-%20Regulation%20of%20actionable%20ISP%20projects%20-%20March%202021%20-%20FINAL%20FOR%20PUBLICATION%2812129318.1%29.pdf.

[104] Australian Energy Infrastructure Commissioner's 2021 Annual Report at https://www.aeic.gov.au/sites/default/files/documents/2022-07/aeic-2021-Annual-Report.pdf.

Mount Alexander, Murray River, Murrumbidgee, and Wagga Wagga.To support the broader community's understanding of and feedback on the PADR, a communication campaign that includes media advertisements in local newspapers, as well as social media and awareness-building via stakeholder channels is being implemented before and during the six-week consultation period.

While the RIT-T is a technical and economic cost benefit test focused on delivering net market benefits, AVP and Transgrid welcome stakeholder feedback on any project-related matters to deepen understanding of the project area and identify engagement opportunities moving forward.

AVP and Transgrid understand that stakeholders may wish to raise important environmental, land-use, safety, amenity, social, cultural and community matters through this early consultation process. While submissions on any topic are welcomed, AVP and Transgrid acknowledge that it may be difficult for communities and potentially impacted landholders to engage on specific matters relating to social and environmental impacts until a narrower investigation corridor has been identified. Once the project is validated from a technical and economic perspective, AVP and Transgrid will also commence an extensive engagement program as part of the route determination process.

Feedback from early engagement activities, as well as input received via submissions during the consultation period, will be used to help inform the PACR. The PACR will include a summary of consultation undertaken and key themes from feedback received.

Should a project be justified through the RIT-T process, any concerns raised that are not yet able to be addressed in this RIT-T phase will be collated and addressed through extensive community and stakeholder consultation as part of the project development phase, design, and subsequent planning approvals.

An indicative timeline for engagement in processes beyond the RIT-T is under development and will be published with the Project Assessment Conclusions Report (PACR) to give regional stakeholders ample time to prepare for meaningful engagement should the RIT-T be successful.

5.2 Land, planning and environment

Since the PSCR, a range of desktop land, planning and environmental feasibility studies have been undertaken to better understand the existing and known conditions relevant to the credible options in this RIT-T assessment.

AVP and Transgrid identified this land, planning and environment feasibility analysis as a key step, usually not undertaken in this detail during the RIT-T process, in identifying and understanding relevant environmental and social values. This analysis ensured that:

- High-level environmental constraints and opportunities were understood at the early investigation and planning stages.
- Land assembly, regulatory planning and environment costs were appropriately estimated to inform transmission investment decisions.
- Transmission options considered were likely to achieve future planning and environmental approvals and as far as practicably possible, are anticipated to be broadly acceptable to the community.

The feasibility analysis sought to identify ways to minimise impact on communities and the environment while balancing key objectives of meeting the identified power system need, technical requirements, addressing cost efficiency, and constructability.

5.2.1 Suitability analysis

The process consisted of analysing existing publicly available environmental and social information, and reviewing lessons learnt from previous and current projects, to identify the environmental constraints and opportunities within the greater geographical areas of each credible option, that is, the ‘areas of interest’.

In undertaking the desktop feasibility analysis, AVP and Transgrid identified a range of significant key land, planning and environmental constraints in the broad geographical area north of Ballarat up to the Victoria – New South Wales border and through to Dinawan which may have significant impacts on the delivery of the credible options (see Table 14 in Appendix Section A2.3 for constraint sources referenced).

These significant constraints (such as airports, town/city centres, national parks) were then designated as ‘no-go areas’, with avoidance measures being applied to the credible options and considered within the prepared cost estimates, to further enhance the accuracy of the estimates.

During the analysis, areas in the broad geographical area that have previously been disturbed were also identified (such as existing transmission lines, roads and tracks, and utility easements), where potential impacts on existing and future land-use could be minimised, such as through co-locating with existing linear infrastructure.

The outcome of this process of analysing existing publicly available environmental and social information, and reviewing lessons learnt from previous and current projects, was to refine a broad geographical area to an ‘area of interest’.

As part of the future route determination exercise, which would follow the completion of the RIT-T process, the area of interest would then undergo more focused assessments, surveys and discussions to further investigate environmental, cultural and social constraints and opportunities. This will allow the reduction of this area of interest to an ‘investigation corridor’.

Having this investigation corridor will potentially allow for activities such as, but not limited to:

- Targeted stakeholder meetings with potentially affected landholders, Traditional Owner groups, conservation bodies, local communities, and federal, state and local government agencies and councils.
- Testing of ongoing investigation findings.
- Identification of local level constraints and opportunities in the investigation corridor, allowing for refining as appropriate (includes the potential for infield visits and survey).
- Detailed multi-criteria analysis (input from targeted meetings and specialist studies) to further refine and identify suitable options in the investigation corridor.

The aim is to identify a route for the project which recognises and takes account of the community, social and environmental impacts within the investigation corridor.

To reiterate, the land, planning and environmental feasibility analysis undertaken at this stage is based on available desktop information only, represents a point in time, is subject to change, and has not been informed by any field investigations, community or landholder engagement, or the specific requirements of any planning and environmental approval processes relevant at the time. Further detailed studies assessing the potential environmental and social impacts will form part of the relevant planning and environmental approval processes as part of the early works for VNI West.

This PADR does not identify a preferred route, and the analysis performed to date has been undertaken on a best endeavours basis to be satisfied that the preferred RIT-T option is feasible, and to inform the cost estimates.

5.2.2 Land access, easements and compensation

It is clear that landholders, parties with interest in land, and electricity transmission companies are critical partners in the delivery of major energy projects and the provision of essential services. The following information on land access, easements and compensation processes would follow a successful RIT-T outcome; it has been provided here to help increase awareness and understanding.

Land access

In support of the relevant planning and environmental approval processes, there is a need to assess the potential impacts that would be associated with the construction and operation of VNI West. In addition to the land, planning and environmental assessments, extensive community and stakeholder consultation would occur as part of the route determination process. This would include working with councils, stakeholders and landholders, in any identified investigation corridor described above, to gain a deeper understanding of existing local constraints and opportunities. The aim is to identify local level constraints and opportunities to inform route options within the investigation corridor and refine as appropriate.

Transgrid and AVP (or parties they contract) would also be required to undertake detailed environmental surveys on private property and would seek agreements to access properties in a manner to minimise disruption as far as practicably possible. These surveys are required to not only identify potential impacts but to identify the ability to avoid, minimise or offset those impacts. Transgrid and AVP would engage communities and landholders to co-design an appropriate landholder liaison program in advance of any such activity.

The current land access process in Victoria and New South Wales is undertaken through either:

- A voluntary agreement between a transmission company and a landholder (which is preferable as it allows the transmission company to work more flexibly around landholder activities on their land); or
- If a voluntary arrangement cannot be reached, transmission companies have powers under section 93 of the *Electricity Industry Act* (Vic) and section 44 of the *NSW Electricity Supply Act* (NSW) to access land compulsorily.

With the potential of understandable concerns around the use of these compulsory land access powers, and little recent experience building major Victorian transmission projects, the Essential Services Commission in Victoria recently developed the 'Electricity Transmission Company Land Access Statement of Expectations'[105] (SoE). This SoE is an interim measure, pending the development of a broader enforceable Code of Practice for land access, expected in 2023. This SoE:

- Seeks to achieve a balance between the statutory right to access private lands and the rights of those affected by that exercise of that power.
- Strives to promote effective engagement between landowners and electricity transmission companies, facilitating land access that is fair and transparent which takes into account the interests of landowners.
- Applies to all electricity transmission companies undertaking major greenfield projects in Victoria, such as VNI West.
- Does not relate to decisions regarding the route of transmission projects or decisions about whether to proceed with these projects.

[105] See https://www.esc.vic.gov.au/electricity-and-gas/inquiries-studies-and-reviews/electricity-transmission-company-land-access-statement-expectations.

AVP or its contractors would adhere to the better practice guidance provided in this SoE if land in Victoria needs to be accessed to progress this project.

Easements and compensation

There is a need for easements which contain transmission lines to ensure public safety and provide access to infrastructure to maintain a reliable transmission network. The size of the easement, based on the currently proposed 500 kV overhead transmission line, would range from 70-100 metres wide.

The preferred method of granting an easement and its terms is through negotiations and agreement between a landholder and the electricity transmission company. However, electricity transmission companies are also able to compulsorily acquire easements over private land to erect, lay and maintain powerlines.

Where an easement is acquired over a property, compensation will be paid to the landholders. All other parties holding an interest in the land on which the easement is located, who suffer loss due to the establishment of the easement or construction activity, will also be considered as part of the compensation process.

A qualified valuer would undertake all compensation valuations, ensuring that the compensation process is undertaken fairly and considers all the impacts the easement may have on the property. The landholder will have opportunities to discuss the determined impacts with the valuer, as well as to obtain independent legal and valuation advice, to assist in the determination of the compensation payable.

Where negotiated agreement cannot be reached, the required easement may be compulsorily acquired with the amount of compensation received by the landholder being based on the regulatory determined compensation valuations. A landholder will still be able to provide evidence of loss in this process to inform the compensation payable.

While there are some restrictions on the use of the land within an easement for overhead transmission lines, there are numerous permitted activities (some with conditions) which may be included in the easement terms, such as grazing and agriculture, irrigation equipment (for example, centre pivot), fencing, construction, vehicles and water storage dams. Activities such as aerial crop spraying would not be permitted.

In New South Wales, Transgrid is required to comply with the *Land Acquisition (Just Terms Compensation) Act 1991*. In Victoria, compliance with the *Land Acquisition and Compensation Act 1986* (Vic) and the *Valuation of Land Act 1960* (Vic) is required.

If the project is justified through the RIT-T process, AVP and Transgrid would work with landholders to identify opportunities to minimise impacts on existing land use throughout the detailed design phase of VNI West.

5.3 Benefits sharing

The current RIT-T process is relatively limited in its ability to explore benefit sharing options. AVP and Transgrid are supportive of the current efforts being undertaken by a number of bodies to find new ways to better share the benefits of projects such as VNI West with the communities that they impact. We recognise that there are opportunities for co-existence that enable better outcomes for local communities by understanding their needs and working collaboratively with them to minimise impacts and seek mutual value opportunities.

Through the proposed Victorian Transmission Investment Framework (VTIF) currently under consultation[106], VicGrid is aiming to deliver social and economic benefits in ways that are fair, meaningful and participatory. This includes ‘*opportunities for earlier and deeper engagement with local communities to help better manage impacts and to make the most of regional development opportunities for host communities’*. Although VNI West will not be delivered under the VTIF, VicGrid has indicated that the principles detailed within the framework should be incorporated into the various phases of the project where possible.

AVP and Transgrid also support the Energy Charter’s work to develop the ‘*Social Licence guidelines for landholder and community co-existence with energy transition infrastructure*’. The aim is to develop ‘*practical guidelines for co-existence between transmission infrastructure and agriculture to mitigate negative impacts and prioritise shared value through the energy transition’*.

[106] Currently at Preliminary Design Consultation Paper stage undergoing consultation, access at https://engage.vic.gov.au/victorian-transmission-investment-framework.

6 Two options have been assessed

The PADR assesses two credible options – one that represents the 2022 ISP candidate option ('VNI West (via Kerang)'), and one building on submissions to the PSCR (involving a 'virtual transmission line' put in place ahead of VNI West (via Kerang)).

6.1 Overview of the options considered

This PADR assesses two different options to provide additional transfer capacity between Victoria and New South Wales, which reflect the 2022 ISP candidate options and the additional use of alternative technologies:

- Option 1: VNI West – a new high capacity 500 kV overhead double-circuit transmission line to connect the Western Renewables Link (north of Ballarat) with Project EnergyConnect (at Dinawan) via new stations near Bendigo and Kerang[107].
- Option 2: A virtual transmission line (VTL) commissioned in 2026-27, involving batteries at South Morang in Victoria and Sydney West in New South Wales, then followed by VNI West.

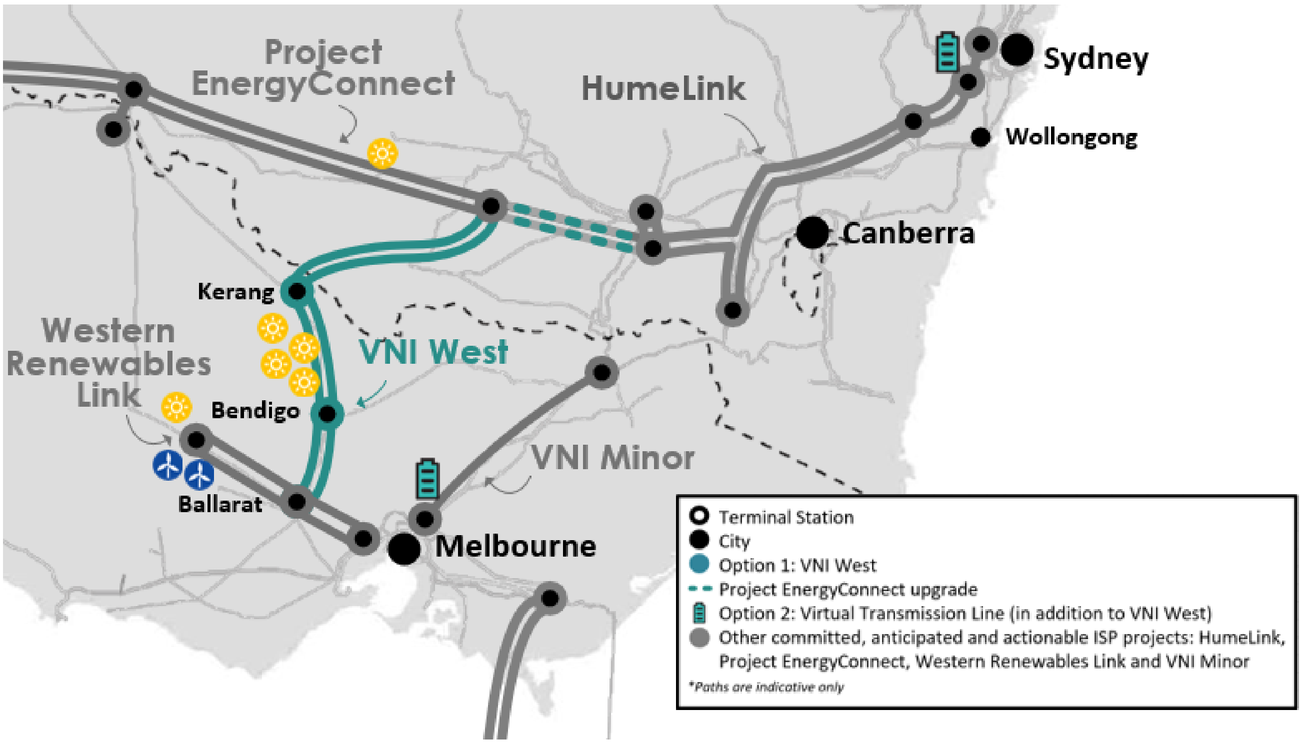
The relatively small number of options assessed in this PADR reflects the further work that has been undertaken as part of the ISP since the PSCR.

Section 6.4 summarises the other options that were previously considered during this RIT-T process, and the reasons why they are no longer being progressed, and Section 6.4 outlines some of the impediments to undergrounding high-capacity high-voltage transmission networks, and why partial undergrounding can only be considered following completion of the RIT-T.

The two credible options are shown in Figure 4 below. All topologies shown are high-level schematic illustrations only and specific line routes are not defined within the PADR.

[107] VNI West (via Kerang) is a refinement of the 'VNI 7' option presented in the PSCR.

Figure 4 Credible options assessed



The technical characteristics of the credible options are summarised in the two tables below. Specifically, Table 3 shows the indicative impact on transfer capacity (in both directions) and the REZ transmission limit[108] (by affected REZ) for each option, and Table 4 shows the expected capital cost for each option by key component (in both Victoria and New South Wales)[109]. More detail on how the cost estimates have been developed is in Section 8.1 and Appendix A3.

Table 3 Summary of the credible options assessed in this PADR – transfer capacities and REZ limits

Option	Indicative impact on transfer capacity		Indicative impact on REZ transmission limit
	VIC to NSW	NSW to VIC	
VNI West	+1,930 MW	+1,800 MW	V2 - Murray River: +1,600 MW V3 - Western Vic: +550 MW N5 - South West NSW: +900 MW*
VTL ahead of VNI West	+250 MW from the VTL +1,930 MW from VNI West	+250 MW from the VTL +1,800 MW from VNI West	Same as VNI West once it is commissioned (that is, no additional REZ hosting capacity associated with VTL component)

* The 2021 IASR published 30 June 2022 (at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/inputs-assumptions-and-scenarios-workbook.xlsx?la=en) includes a South West New South Wales REZ transmission limit increase of 900 MW from VNI West. This increase was not modelled in the Draft 2022 ISP or this PADR due to the timing of the change. AVP and Transgrid do not consider this has a material impact on the ranking of the options or the conclusion of this PADR assessment. It may, however, underestimate the benefits of the project for consumers.

[108] REZ transmission limits represent the maximum generation that can be dispatched at any point in time within a REZ, the additional generation development can exceed these limits as VRE generation does not always operate at full capacity. Refer to Section 3 for generation development forecasts.

[109] All costs and benefits in this PADR are presented in FY2020-21 dollars, unless otherwise stated.

Table 4 Summary of the credible options assessed in this PADR – capital costs, $m in FY2020-21 dollars

Cost component	Option 1 VNI West		Option 2 VTL ahead of VNI West	
	NSW	VIC	NSW	VIC
Stage 1 – Early works				
Early works – Property/land access/easements	66	56	83	73
Early works – other	50	88	50	88
Project EnergyConnect enhanced (incremental line build cost)	182	0	182	0
Stage 2 - Implementation				
Substation works	354	641	354	641
Line works	751	708	751	708
Battery costs	0	0	288	295
Modular power flow controllers	183	89	183	89
Biodiversity offset costs	66	24	66	24
Total (by state)	1,651	1,605	1,957	1,918
Total (all states)	3,256		3,874	

The cost estimates presented above for the Victorian component of the options (and therefore also the total cost estimates) differ from the cost estimates in the final 2022 ISP, due to the inclusion of an additional contingency allowance. This is discussed further in Section 8.1.

Annual routine operating and maintenance costs are assumed to be 1% of capital costs for transmission assets, including early works, substation works, lines works and modular power flow controllers (but excludes land related costs and biodiversity offset costs). In addition, Victorian land taxes are assumed to be approximately $800,000 per year. VTL components are assumed to incur routine operating and maintenance costs of $2.5 million per annum once the VTL components have been commissioned.

A specific route for the preferred option will only be confirmed following completion of the PACR. An extensive range of factors may affect the project cost including (but not limited to) environmental factors affecting line route, biodiversity considerations, land acquisition or easement cost, construction cost implications arising from route dynamics, currency fluctuations and construction contractor costs in the proposed construction period. As such, the costs specified are indicative only at this stage and will be subject to further refinement[110].

As part of a broader set of integrated developments in the NEM, VNI West would connect Western Renewables Link (north of Ballarat) with Project EnergyConnect (at Dinawan), via new stations near Bendigo and near Kerang. Western Renewables Link and Project EnergyConnect are both new projects under development. The western section of Project EnergyConnect (Robertstown to Buronga via Red Cliffs) obtained planning approval and construction has commenced. The New South Wales eastern section (Buronga to Wagga Wagga) is undergoing an Environmental Impact Statement (EIS) review process and awaiting approval. Western Renewables Link is in the preparatory stage of the Environment Effects Statement (EES), as mandated by the Minister for Planning in August 2020, and is therefore yet to receive the required environmental and planning approvals. For the purpose

[110] The revised cost estimates in this PADR are considered to have an accuracy of +/- 30%, which AVP and Transgrid consider to be 'class 4' estimates and in line with the level of accuracy typical at this stage of the investment process.

of this RIT-T, Project EnergyConnect and Western Renewables Link are treated as anticipated projects and are assumed to be delivered in a timely manner to allow VNI West to connect efficiently to the network. If any modifications are required as a result of the EIS or EES processes, respectively, in order to obtain environmental and planning approvals, the impact of these modifications will be assessed to determine if any consequential changes to VNI West would be required that could materially change this RIT-T assessment.

The remainder of this section provides further detail on each of the two credible options. It also summarises the options considered earlier in this RIT-T process but which are not now being progressed (with the reasons why).

AVP and Transgrid have performed extensive power system analysis to assess the thermal, voltage stability, transient and oscillatory stability limits associated with each credible option considered. This analysis has confirmed that, while the options assessed in this RIT-T are expected to have material inter-network impacts, these impacts are not adverse.

6.2 VNI West – Option 1

VNI West is a new high capacity 500 kV double-circuit transmission line to connect the Western Renewables Link (north of Ballarat) with Project EnergyConnect (at Dinawan) via new stations near Bendigo and Kerang. This aligns with the ISP candidate option in the 2022 ISP[111] and 'VNI 7' in the PSCR and the 2020 ISP (noting that there have been a number of modifications to the scope of this option since the PSCR – see Table 6 below).

It comprises the following augmentations:

- A new 500 kV double-circuit overhead line from north of Ballarat to near Bendigo to near Kerang to locality of Dinawan.
- Construction of the Dinawan to near Wagga Wagga line as a double-circuit 500 kV line, rather than a double-circuit 330 kV line and later upgrade from 330 kV to 500 kV operation (including new 500 kV bays and a transformer station near Wagga Wagga).
- Establish Dinawan 500 kV switchyard with two 500/330 kV 1,500 megavolt-amperes (MVA) transformers.
- New substations near Bendigo and near Kerang.
- Two 500/220 kV 1,000 MVA transformers at each of the new substations near Bendigo and near Kerang.
- 220 kV connections from the existing terminal station at Bendigo to new terminal station near Bendigo.
- 220 kV connections from the existing terminal station at Kerang to new terminal station near Kerang.
- Modular power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang and 220 kV lines between Dederang and Thomastown following certain contingencies.
- 500 kV line shunt reactors at both ends of the four following 500 kV circuits: (i) north of Ballarat – near Bendigo, (ii) near Bendigo – near Kerang, (iii) near Kerang – Dinawan and (iv) Dinawan – near Wagga Wagga.
- Up to +/- 400 megavolt-amperes reactive (MVAr) dynamic reactive compensation at the new 220 kV terminal station near Kerang.

This scope aligns with the ISP candidate option in the 2022 ISP[112].

[111] AEMO, 2022 ISP, Appendix 5. Network investments, June 2022, p. 27.
[112] AEMO, 2022 ISP, Appendix 5. Network investments, June 2022, p. 27.

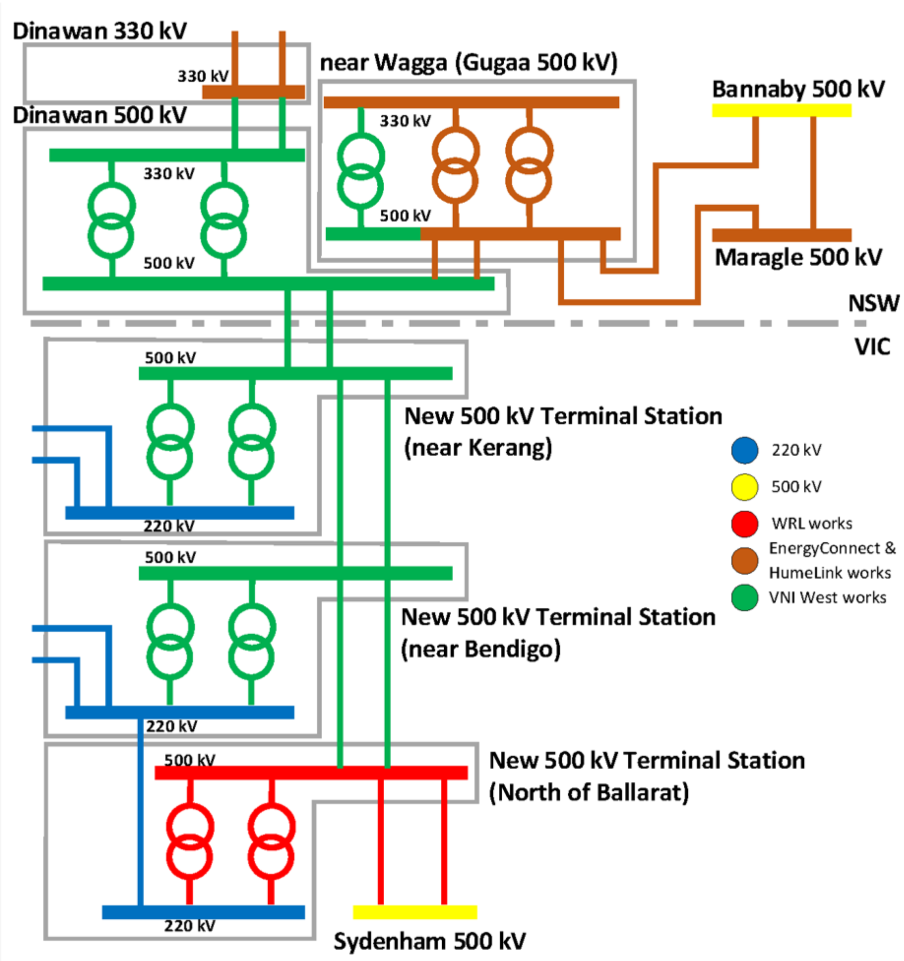
Figure 5 below provides a single-line diagram for VNI West.

Preliminary modelling indicates that this option will result in additional transfer capacity of approximately 1,930 MW from Victoria to New South Wales and 1,800 MW from New South Wales to Victoria. AVP and Transgrid note that these are substantial increases in transfer capacity and are comparable to a large baseload power station in the NEM[113,114].

It is also estimated that VNI West will increase the transmission limit at the following REZs by:

- 1,600 MW in the Murray River REZ (V2).
- 550 MW in the Western Victoria REZ (V3).

Figure 5 Single-line diagram for VNI West



The estimated capital cost of this option is approximately $3,256 million, which is comprised of $1,605 million in Victoria and $1,651 million in New South Wales.

[113] For example, Loy Yang A has a nameplate capacity of 2,225 MW.

[114] The 1,930 MW and 1,800 MW are considered underestimates of the increase in transfer capacity, since the base case already assumes that the Dinawan to Wagga Wagga portion is upgraded to 500 kV (as outlined in Section 2.6).

Construction, including detailed design, construction and 12 months of inter-network testing, is expected to take five years (excluding time for early works), with commissioning depending on the scenario modelled, as outlined in Table 5.

Table 5 Assumed timing for VNI West

Scenario	Stage 1 (early works)	Stage 2 (based on ISP timing for each scenario)
Step Change	Now until 2025-26	July 2031
Progressive Change		July 2038
Hydrogen Superpower		July 2030

Achievement of all delivery dates is subject to obtaining the necessary planning and environmental approvals, assembling land and easements, detailed design, and extensive community and landholder engagement, which is expected to take 3-4 years to complete.

There have been a number of modifications to the scope of this option since the PSCR, as outlined in Table 6.

Table 6 Scope of refinements to VNI West since the PSCR

Scope refinement	Overview
Power flow controllers	Since the PSCR, AVP and Transgrid have tested the technical feasibility of a range of power flow control solutions, as an alternate to traditional phase-shifting transformers or reactive compensation solutions, as part of the network option, that is, VNI West. The outcome of this analysis is that VNI West now includes modular power flow technology as part of its scope. AVP and Transgrid have also investigated a sensitivity that removes the power flow controllers from VNI West, which confirms that their addition is net beneficial (that is, the expected net benefits of Option 1 are lower with the power flow controllers removed). This sensitivity is presented in Section 9.5.1.
Substation connection at Dinawan rather than Darlington Point	Since the publication of the PSCR, Transgrid has changed the route of Project EnergyConnect following design optimisation activity. The preferred route now features a more direct path from Buronga to Wagga Wagga and no longer diverts via the existing Darlington Point substation, where new line entries are physically constrained. As a result of the new route, the scope of Project EnergyConnect includes a new substation south of Darlington Point, known as Dinawan. This also incorporates a new double-circuit 500 kV line from Dinawan to Wagga Wagga (initially operated at 330 kV), instead of a double-circuit 330 kV line from Darlington Point to Wagga Wagga as previously planned. Consequently, the 500 kV lines for VNI West, which in the PSCR connected to Darlington Point, are now assessed as connecting to Dinawan.
New double-circuit 500 kV overhead line from Dinawan to Wagga Wagga	As outlined in Section 2.4, the modification of Project EnergyConnect to include the new Dinawan substation and the commitment by Transgrid and the Commonwealth government to build the Dinawan to Wagga section of Project EnergyConnect to be able to be operated at 500 kV, has provided an opportunity to also modify VNI West to reduce the overall cost of its development. The implications for this RIT-T are that the costs of this portion of the VNI West options assessed in this PADR have fallen since the PSCR. Specifically, while the original scope of the VNI West option included a new 500 kV line from Dinawan to Wagga Wagga, the new scope (and so cost) now only reflects the incremental works involved with building the line at a higher capacity initially (that is, as a 500 kV line rather than a 330 kV line) and the subsequent costs associated with enabling the line to be operated at 500 kV rather than 330 kV.
New terminal station near Bendigo	Desktop due diligence undertaken since the PSCR identified that the existing terminal station at Bendigo is physically constrained and unable to be expanded to include the augmentation identified in this option. Given the location of the existing terminal station within a major regional city, additional land, planning and environmental matters were identified as threshold constraints to the delivery of the option within reasonable time and cost parameters. Accordingly, it is considered more prudent to establish a new terminal station near Bendigo to provide for the delivery of the option within reasonable cost and time parameters and which does not preclude future potential connections.

Scope refinement	Overview
New terminal station near Kerang	Desktop due diligence undertaken since the PSCR identified that the existing terminal station at Kerang is substantially constrained and complex to augment due to the orientation of the existing equipment and limitation of available land within the existing site boundary for expansion. Given the location of the existing terminal station on the edge of a rural town, additional land, planning and environmental matters were identified as complexities. The existence of a nearby wetland of international importance was identified as a threshold constraint. Accordingly, it is considered more prudent to establish a new terminal station near Kerang to provide for the delivery of the option within reasonable cost and time parameters and which does not preclude future potential connections.
Reactive plant	Analysis undertaken for the PADR has confirmed the need for 100 MVAr shunt line reactors at both ends of each 500 kV line proposed for VNI West to maintain system voltage. This includes two additional 100 MVAr reactors at Dinawan, which were not accounted for in the PSCR. This assessment also re-confirmed the need for approximately +/- 400 MVAr static VAr compensation required at the new terminal station near Kerang, consistent with the PSCR.
Social license and network topology considerations	As outlined in Section 4.10, many submitters to the PSCR commented on how VNI West (via Kerang) has a favourable topology in terms of social impact and network topology considerations, compared to other options considered in the PSCR that traversed through north-east Victoria. Transgrid and AVP have put significant effort into assessing and mitigating the impact of VNI West (via Kerang) on the surrounding environment since the PSCR and the cost estimates include allowance for this.

6.3 Virtual Transmission Line ahead of VNI West – Option 2

The PSCR sought submissions from providers of potential non-network solutions for information on options that may be capable of addressing or partially addressing the identified need.

In response, two submissions were received that proposed VTL solutions, with both submissions noting that the solutions could be commissioned ahead of any wider network development. AVP and Transgrid engaged with these non-network providers to discuss the VTL options proposed in submissions.

Informed by this feedback, and further assessment by AVP and Transgrid, a non-network VTL has been included as a component of a second credible option in the PADR assessment, combined with VNI West

The VTL solution assessed involves installing battery energy storage solution (BESS) pairs and, in the event of a contingency, co-ordinating the charging/discharging of the batteries, enabled by a purposely designed controller, to quickly reduce post-contingent power flows to within post-contingent transmission limits. The fast and co-ordinated post-contingent action of the batteries allows an increased pre-contingent VNI capacity while managing potential post-contingent overloads.

The VTL solution assessed has been optimised as two 250 MW/125 megawatt hour (MWh) BESS systems based on the existing interconnector lines utilising their highest-capacity, shortest-duration, ratings operationally feasible. That is, the optimised BESS sizing allows pre-contingent transfer across the existing VNI to be maximised while maintaining sufficient time, through BESS charging/discharging, to re-dispatch generation post-contingency without overloading the existing VNI lines.

6.3.1 A VTL could be implemented ahead of the network solution to provide benefits sooner

AVP and Transgrid do not consider that a VTL solution constitutes a credible standalone option as it, by itself, cannot meet the identified need as set out in the 2022 ISP. In particular, AVP and Transgrid do not consider that a VTL alone can realistically satisfy the element of the identified need referring to 'efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in ageing generator reliability – including mitigation of the risk that existing plant closes earlier than expected'[115], since it is not of

[115] AEMO, 2022 ISP, June 2022, p. 74.

sufficient capacity to provide the required risk mitigation. Using Loy Yang A as an example, this generator has a nameplate capacity of 2,225 MW, which is significantly greater than the VTL (250 MW).

However, this does not preclude a VTL or similar technology from being considered as a stand-alone solution to a separate need identified by AVP or Transgrid in their annual planning processes.

AVP and Transgrid have therefore considered a VTL as a component of a combined option, with VNI West.

A VTL option has the potential to be implemented more quickly than investment in a new transmission line and to relieve network congestion ahead of the line being in place. This in turn has the potential to facilitate the efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales and enable more efficient sharing of resources between NEM regions (the other two elements of the identified need for this RIT-T).

A VTL has therefore been assessed in this PADR as an additional component that could be put in place ahead of the commissioning date for VNI West. Inclusion of this as a second option in the RIT-T tests whether the addition of a VTL to VNI West is expected to provide additional net benefits over and above the VNI West option.

If a VTL option is ultimately preferred at the conclusion of this RIT-T, there would be a subsequent procurement process for both batteries (separate to the RIT-T process).

The timing of the VTL component is assumed to be the earliest possible date it can be commissioned (1 July 2026 – that is, 2026-27 – reflecting a three-year development/build time). The assumed VTL in-service date is the same in all three scenarios and the timing of the VNI West component remains the same as that for Option 1, for each scenario.

6.3.2 Scope of a VTL

In the specific circumstances of this RIT-T, the VTL option assessed involves two new batteries (one at South Morang in Victoria and one at Sydney West in New South Wales) that will receive signals from relevant locations of the network.

The specific scope of the VTL component modelled in this PADR has been informed by submissions from proponents and is as follows:

- 1 x 250 MW/125 MWh BESS at South Morang in Victoria.
- 1 x 250 MW/125 MWh BESS at Sydney West in New South Wales.
- 1 x 220/33 kV transformer at South Morang, and associated works.
- 1 x 330/33 kV transformer at Sydney West, and associated works.

This VTL is intended to be operated in response to a network contingency during periods when existing VNI transfer is constrained by transmission limitations in either Victoria or New South Wales. In the jurisdiction experiencing the constraint, the BESS will be available to discharge instantaneously at rated capacity (250 MW) for a period of 30 minutes in response to a contingency event, which allows the network operator to run thermally constrained lines at higher short-term emergency ratings pre-contingency and can also increase transient stability limitations. The BESS will also be available to inject reactive power to boost voltages in areas of the network that experience voltage instabilities. This effectively increases the VNI transfer limit from the existing interconnector by up to 250 MW, in either direction, by allowing higher transfers across highly loaded lines.

As outlined in Section 2.4, since the PSCR, AVP has entered into the SIPS Support Agreement with the Victorian Big Battery to allow additional import (from New South Wales to Victoria) of electricity over the existing VNI of up to 250 MW at peak times between November and March. The implications of this are that the expected benefits of the VTL component are now lower than they otherwise would be, since the base case includes the operation of the SIPS until March 2032 (after this the Big Battery is assumed to be able to freely arbitrage in the base case as an uncontracted battery). Nonetheless, even with the SIPS contract in place, a VTL could still operate for the period each year outside of the contracted SIPS period (which is from 1 November to 31 March each summer), could operate for increased export to New South Wales (including during the SIPS period), and could reduce the impact of voltage and transient stability constraints that limit VNI transfer under some network conditions.

AVP and Transgrid expect to only contract the VTL for the period before VNI West is commissioned – that is, the assumed contract term varies depending on the scenario modelled:

- *Progressive Change* – the VTL is contracted from 1 July 2026 to 1 July 2038.
- *Step Change* – the VTL is contracted from 1 July 2026 to 1 July 2031.
- *Hydrogen Superpower* – the VTL is contracted from 1 July 2026 to 1 July 2030.

While the two batteries are not assumed to be able to arbitrage for the duration of the assumed VTL contract period for each scenario (that is, they are assumed to be contracted year round for the VTL service), they are assumed to revert to having their full capacity available for energy arbitrage market operation after conclusion of the VTL contract period.

The estimated capital cost of the VTL component is approximately $618 million, which is comprised of:

- $583 million in battery costs ($295 million in Victoria and $288 million in New South Wales).
- $35 million in property/land access/easements ($17.5 million in Victoria and $17.5 million in New South Wales).

The cost of the VTL component has been based on generic costs for the battery component at this stage, including from the 2021 IASR, and informed by the costs put forward by the two proponents. The associated network components have been estimated in line with the network components of VNI West, as outlined in Section 8.1 and Appendix A3.

6.3.3 Technical feasibility would need to be investigated further

AVP and Transgrid note that there are voltage and transient stability limits that may limit the feasibility of the VTL component of Option 2 (and which form the binding constraints, ahead of thermal limitations[116], in the market modelling).

In addition, AVP and Transgrid note that technical feasibility of this option depends on the response time of the batteries (which is expected to need to be within 200 milliseconds (ms) ramp-up time) and also the protection and control systems, including the network communications. AVP and Transgrid would need to undertake additional system studies to confirm response times if the VTL forms part of the preferred option for this RIT-T. Initial discussions with proponents confirmed that the proposed solutions can be designed to have the required response times.

[116] The thermal constraint becomes the binding constraint during the peak demand period after the SIPS contract concludes.

For the purposes of the PADR, the VTL component is assumed to be technically feasible in order to determine whether it is likely to form part of the overall preferred option (which would justify the significant additional work required to comprehensively determine technical feasibility).

6.4 Undergrounding

Options to underground the lines were raised in submissions to the PSCR, and continue to be suggested by stakeholders and communities as possible solutions that could help minimise social and environmental impacts of the project. Delivery of high-capacity 500 kV underground lines, along the full length of the project, is not economically feasible based on current cost assumptions and has known technical challenges that need to be considered on a project and route specific basis. Some of the factors, which are discussed in more detail below, include:

- HVDC (both overhead and underground options) not meeting the identified need of VNI West.
- Underground HVAC being significantly more expensive than HVAC overhead.
- Cable joints being required at regular intervals along the length of any underground sections.
- Differences in reliability and fault restoration.
- Limited supply of underground expertise.
- Shorter asset life expectancy of underground cables.
- Construction differences between overhead and underground installations
- Operational differences between overhead and underground installations
- Underground cables requiring narrower easements.

While some of these factors vary between HVAC and HVDC technology, the cost and technical impediments to meeting the identified need through full undergrounding are significant and have resulted in the VNI West options assessed and presented in this PADR being based on overhead alternating current (AC) transmission technology.

Despite this, AVP and Transgrid acknowledge the importance of considering partial undergrounding in exceptional circumstances driven by significant technical, environmental and/or social factors. These factors are route-specific and can therefore only be investigated as part of the project's early works stage, following the RIT-T process.

6.4.1 HVDC (both overhead and underground options) not meeting the identified need of VNI West

Compared to HVAC, HVDC is used in more targeted applications such as point-to-point interconnection, as applied for Basslink, Murraylink and Marinus Link, or to connect individual inverter-based resources to an AC network, for example offshore wind. Since a key part of the identified need for VNI West is to facilitate efficient development of generation in areas with high quality renewable resources in Victoria and southern New South Wales, point-to-point HVDC is not a feasible option capable of meeting VNI West's identified need.

While HVDC underground cable is lower cost than HVAC on a per length of cable basis, it requires a converter station at each end of the cable, and at any connection point along the cable, to convert between direct current (DC) and AC. The addition of converter stations, which can cost 2-3 times that of a high voltage AC terminal station and require land size similar to, and in addition to, the AC terminal station, typically make HVDC a more expensive option than HVAC in instances where multiple connections along the route are anticipated.

6.4.2 Underground HVAC being significantly more expensive than HVAC overhead

AusNet Services prepared a preliminary cost estimate to underground its Western Renewables Link. This assessment indicated that the cost of underground construction on that project could be up to 16 times the cost of overhead construction for a comparative HVAC solution[117].

At a high level, and on a length per cable basis, the AEMO Transmission Cost Database[118] indicates that undergrounding HVAC cables costs in the order of 20 times that of the equivalent HVAC overhead line. This price differential considers the cable only and does not consider the costs of constructing the transition stations, which are required at locations where the circuit transitions between underground and overhead. Each transition station is similar in size to a small transmission switching station, and typically costs approximately $105 million per station.

The cost of underground cable installation is highly dependent on the terrain and soil characteristics along the route. A complete in-depth study and characterisation of the subsurface and electrical environment is necessary to get an accurate cost estimate for undergrounding a specific section of transmission.

6.4.3 Cable joints being required at regular intervals along the length of any underground sections

The high-capacity cables that would be required to deliver equivalent capacity to the overhead circuits considered for VNI West, would be very large and hence require joins at regular intervals. Cable joints are installed in joint vaults which are large concrete boxes, with an approximate footprint of 60 square meters and 1.5 meter depth, buried along the underground construction route. In addition to splicing (joining) cables during construction, these vaults are also used for permanent access, maintenance, and repair of the cables.

The number of vaults required for an underground transmission line is dictated by the maximum length of cable that can be transported on a cable drum, the cable's allowable pulling tension, elevation changes along the route, and the sidewall pressure as the cable goes around bends.

For high-capacity 500 kV cable, as would be required for VNI West, it is expected that a minimum of three cables per phase would be required and would need to be spliced (joined) approximately every 500-1,000 meters. Therefore, three cable vaults would be required, adjacent to each other, every 500-1,000 meters along the entire length of any underground cable sections.

6.4.4 Differences in reliability and fault restoration

Overhead and underground lines are exposed to different types of outage and reliability risks. Unlike underground cables, overhead lines are exposed to weather related outages, such as those caused by lightning strikes. However, the large number of cable joints required for underground high voltage cables increase the risk of failure. In the event of a cable fault, locating and repairing the fault can be challenging and time-consuming, and

[117] AusNet, Western Renewables Link Underground construction summary, November 2021, p.16. At https://www.westernrenewableslink.com.au/assets/resources/Underground-construction-summary-November-2021.pdf.

[118] At https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

may take several weeks / months to repair. The duration of outages varies widely, depending on the circumstances of the failure, the availability of parts, and the skill level of the available repair personnel.

The typical outage of a 500 kV cable fault is estimated from 3-6 months and may involve the excavation of hundreds of meters of the cable depending on the type of fault and the extent of the damage. During this time, the circuit capacity will be significantly reduced.

In contrast, a fault or failure of an overhead line can usually be located almost immediately and repaired within hours or, at most, a day or two. A worst-case scenario where a tower has failed, the majority of supply can be restored, even on temporary structures, within 3-5 days.

6.4.5 Limited supply of underground expertise

The expertise available that can install and repair underground cables gets more rare the higher the voltage. There are only a handful of personnel who have the cable expertise at 500 kV and most of these are tied to a cable supplier further limiting availability.

The duration of outages varies widely, depending on the circumstances of the failure, and the availability of parts. However, they are almost always planned around the availability of suitably skilled repair personnel.

Additionally, the expertise required to manufacture underground cables is limited, which would delay the delivery of VNI West compared to an overhead technology.

6.4.6 Shorter asset life expectancy of underground cables

Underground transmission lines, especially at 500 kV, have higher life cycle costs than overhead transmission lines when combining construction repair and maintenance costs over the life of the line.

In addition, most cables are only supplied by the manufacturer with a maximum design life of 40 years. Overhead transmission lines, on the other hand, can have a design life of 80-100 years. This means that in order to match the life expectancy of an overhead line, a cable system will have to be replaced after 40 years, significantly increasing the ultimate cost of the solution. This is not factored into the capital cost comparison discussed above.

6.4.7 Construction differences between overhead and underground installations

Installation of an underground transmission cable generally involves the following sequence of events:

1. Clearing.
2. Trenching/blasting.
3. Laying of conduit.
4. Joint vault installation.
5. Backfilling.
6. Cable installation.
7. Site restoration.

The required continuous trench for the construction of underground lines causes greater soil disturbance than overhead lines, limiting the ability to avoid directly impacting environmental and culturally sensitive areas. Overhead line construction disturbs the soil mostly at the site of each transmission tower and can be micro-sited to avoid sensitive areas.

6.4.8 Operational differences between overhead and underground installations

Post-construction, trees and large shrubs would not be allowed within the easement of underground cables due to potential problems with roots. Certain vegetation and agricultural crops with shallow root systems may be allowed to return to the easement. However, these may need to be removed if the ground is required to be excavated for cable repairs. In terms of overhead lines, native vegetation can be retained within the easement up to a limited height.

Underground cables have improved visual and noise amenity as they are not visible after construction and have less impact on nearby property values and aesthetics. Overhead lines may have the potential to impact on visual amenity in sensitive locations.

Overhead lines, during certain climatic conditions, experience corona breakdown. This corona breakdown, which has a cracking sound, occurs when there is a temporary breakdown of the insulation of the air around the conductor. The noise associated with this corona breakdown can only be heard in close proximity to the overhead line. This effect does not occur in underground cable installations.

Underground cables are not exposed to bushfire events and do not hinder aerial firefighting activities. Overhead lines may be required to be deenergised before safe operation can occur by firefighting crews.

While land use activities such as grazing are permitted for both underground and overhead cables, location of structures are restricted within easements. When it comes to underground cables specifically, there is no restriction on irrigation methods or height of machinery as there would be with overhead. Although not restricted in terms of height, there is a restriction on weight of machinery when it comes to entering an underground easement.

These operational differences highlight why undergrounding decisions are very route-specific – in some circumstances it may impede existing land-use.

6.4.9 Underground cables requiring narrower easements

Underground lines require a narrower easement width of approximately 55 meters compared to an overhead line easement of 70 meters.

6.5 Alternative options considered but not progressed

A number of additional options have been considered at various stages over the course of this RIT-T, and the associated ISP assessment. These include:

- Options proposed in submissions to the PSCR.
- Variations of VNI West.
- Options discounted in the 2020 ISP.
- Options discounted in the 2022 ISP.
- Options from the PSCR.

Table 7 below summarises each of these options and why they have not been progressed as part of the PADR assessment.

Under the actionable ISP framework in the NER, the ISP now provides guidance to the RIT-T proponent on options to consider in the RIT-T[119]. To avoid duplication between the ISP and RIT-T, credible options considered in the ISP that do not form part of the optimal development path need not be retested in the RIT-T. As a consequence, some of the options that were previously included in the PSCR and which were subsequently considered in the 2020 and 2022 ISP, but did not form part of the optimal development path[120], have not been progressed (in accordance with NER clause 5.15A3(b)(8)(i)).

Table 7 Alternative options considered but not progressed

Option	Overview	Reason(s) it has not been progressed
Options proposed in submissions to the PSCR		
220 kV upgrades	Low-cost options in the 220 kV network.[A]	220 kV options were not recommended as part of the 2020 ISP or 2022 ISP. A larger augmentation is required, as this option would not provide significant additional REZ hosting capacity, or interconnection transfer capacity.
Option from a confidential submission	An alternative option was proposed in a confidential submission. The detail of the proposed option is not presented due to confidentiality obligations.	The option was not considered credible as it had a longer, less efficient topology that increased costs but did not provide a corresponding increase in benefits. It is therefore not considered commercially feasible. A response has been provided to the submitter.
Undergrounding	Underground either in whole or part of VNI West to reduce the impact on visual amenity.	The delivery of high-capacity high-voltage 500 kV underground lines would be unprecedented for the NEM, and unlikely to meet the 2022 ISP cost and time requirements (particularly, the timeframes under the *Step Change* and *Hydrogen Superpower* scenarios). Notwithstanding, undergrounding, either in whole or in part, was considered in response to submissions raising matters of social and environmental impacts, particularly as they relate to visual amenity. See Section 6.4. While full undergrounding is considered a cost prohibitive solution to balancing community and stakeholder expectations, while still meeting the identified need, AVP and Transgrid acknowledge the importance of considering partial undergrounding in exceptional circumstances and are committed to working closely with community and stakeholder groups to consider cost effective alternatives to undergrounding, such as route diversion, screening, and line tower design, that can help manage the broad and real social and environmental impacts.
Variations to VNI West		
Connection via Donnybrook	A possible alternative starting point included in the 2020 ISP is through Donnybrook, instead of a new terminal station north of Ballarat.[B]	This alternative connection point was ruled out in the 2020 ISP. It has therefore no longer been considered in this RIT-T. Specifically, this alternative was considered but not progressed in the 2022 ISP due to the scope of Project EnergyConnect having changed since the publication of 2021 IASR where it now involves building double-circuit lines from Dinawan to Wagga Wagga at 500 kV and operating them initially at 330 kV. This has reduced the cost estimate for the VNI West options assessed in this PADR and provides increased connection to the South West New South Wales, Murray River and Western Victorian REZs.[C] Consequently, this alternative via Donnybrook is considered less cost competitive without corresponding benefits and so was not progressed as an option in the 2020 ISP and this PADR.
Staging of option capacity	The possibility of staging capacity for options by building to 500 kV and initially operating at 330 kV, or by stringing on only one side initially.	The possibility of staging capacity by building to 500 kV but initially operating at 330 kV, or by stringing only one side initially, was considered but not progressed as part of this PADR since the cost is nearly the same as for the credible options assessed. This is due to the easement requirements (and associated costs) remaining the same and, in the case of operating at 330 kV initially in Victoria, which has a

[119] AER, Final decision Guidelines to make the Integrated System Plan actionable, August 2020, pp. 50-75. At https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Guidelines%20to%20make%20the%20ISP%20actionable%20-%2025%20August%202020.pdf.

[120] See Table 57, 'Discounted options to increase interconnection between New South Wales and Victoria', at https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--3.pdf?la=en.

Option	Overview	Reason(s) it has not been progressed
		220 kV system, having to introduce new 220 kV/330 kV terminal stations. The staging of option capacity would also introduce uncertainty for generators and other parties seeking network connections as to the voltage that connection assets should be specified to.
Staging of VNI West by sections	The possibility of staging the section from a new terminal station north of Ballarat to Kerang first, with sections from Kerang to Dinawan and Wagga Wagga following after. This would allow for 1,000 MW of generation from the Murray River REZ (V2) to be harnessed first.	Developing portions of the scope sequentially is not considered able to meet the identified need as set out in the 2022 ISP. For example, while it may marginally add to Victoria's reliability, it would not materially improve the efficiency of development and dispatch of generation in southern New South Wales.
Options discounted in the 2022 ISP [D]		
VNI 6	A double-circuit overhead 500 kV line from a terminal station north of Ballarat via a new terminal station near Shepparton to Wagga Wagga.[H] VNI 6 – Variant 1 involves new 500 kV transmission lines from a new terminal station north of Ballarat to Bendigo to Wagga	The VNI 6 option put forward in the PSCR and the 2020 ISP was ruled out in the 2022 ISP. It has therefore no longer been considered in this RIT-T. Specifically, this option was considered but not progressed in the 2022 ISP due to the scope of Project EnergyConnect having changed since the publication of the 2021 IASR where it now involves building double-circuit lines from Dinawan to Wagga Wagga at 500 kV and operating them initially at 330 kV. This has reduced the cost estimate for the VNI West options assessed in this PADR and provides increased connection to the south-west New South Wales, Murray River and Western Victorian REZs.[I] Consequently, this VNI 6 alternative now has a similar cost to VNI West but lower market benefits due to unlocking less REZ hosting capacity compared to going via a new station near Kerang and so was not progressed as an option in the 2022 ISP and this PADR. Additionally as noted in Section 4.10, a number of submitters to the PSCR raised concerns with the VNI 6 topology running through higher value agricultural farmland, including a high concentration of irrigation infrastructure investment and related agricultural production, which would likely impact timing and cost of construction as well as limiting development of new renewable generation in the area.
Options discounted in the 2020 ISP [E]		
VNI 3	Incremental network augmentation, which includes a series capacitor on the Wodonga–Dederang 330 kV line, a power flow controller on the Jindera–Wodonga 330 kV line, an additional 330/220 kV transformer at Dederang, and additional reactive plant.	AEMO, in its 2020 ISP, concluded that a larger augmentation is required, and that this option does not provide significant additional REZ hosting capacity.
VNI 4	Includes VNI Minor and a new 330 kV transmission line from Dederang to Yass via Jindera and Wagga Wagga.	AEMO, in its 2020 ISP, concluded that a larger augmentation is required, and that this option does not provide significant additional REZ hosting capacity.
VNI 5A **(Included in the PSCR)**	Strengthening the existing VNI corridor by establishing new 330 kV single-circuit transmission lines from South Morang to Dederang to Murray.	This option was discounted by the 2020 ISP analysis as it did not provide additional REZ hosting capacity and did not unlock the development, dispatch and sharing of renewable generation, especially in high quality REZs in northern and western Victoria and south-western New South Wales. It also does not offer interconnector diversity and therefore does not provide additional supply reliability or system resilience (particularly with respect to credible contingency events impacting both the existing line and option VNI 5A simultaneously) due to the shared route along the existing VNI corridor being vulnerable to bushfire.
VNI 9	VNI West going via either Kerang or Shepparton plus an extension from Bannaby to Sydney to remove network constraints between Bannaby, Marulan, Kangaroo Valley and the Sydney West/Sydney South area.	Extension considered in part of Reinforcing Sydney, Newcastle and Wollongong (another actionable ISP project).[F]
VNI 10	VNI Option 9 plus third 500 kV line from Wagga/Maragle to Bannaby. The third line	The 2020 ISP considered this option to increase transfer from Snowy to Sydney but did not find that it formed part of the optimal

Option	Overview	Reason(s) it has not been progressed
	can be a second circuit in a double-circuit tower configuration	development path. It also noted that this option provides no additional increase in transfer capacity between New South Wales and Victoria (which is part of the identified need in this RIT-T), relative to VNI 7, but with a higher cost
VNI 11	This option considered a new 2,000 MW high voltage direct current (HVDC) path which directly connects large Victorian demand centres in the greater Melbourne and Geelong area with the Snowy mountains area in New South Wales. Two new 1,000 MW HVDC transmission lines would connect from Sydenham Terminal Station or a new terminal station at Donnybrook to Wagga Terminal Station, with HVDC converter stations at both locations and an additional converter station in between to host renewable development.	While this option would improve the reliability outlook for Victoria and enable resource sharing between Victoria and New South Wales, it would be less flexible in facilitating the efficient development of future generation in areas with high quality renewable resources, and in providing an access point for this future generation to a high capacity interconnector, as this would require the establishment of an AC-DC converter station at each connection location. The 2020 ISP stated that this option is more expensive than VNI West (via Kerang) when considering the need to host renewable development in nearby REZs [G]. This was reconfirmed in the 2022 ISP and therefore is not considered credible.
Other options from the PSCR		
Expansion A and Expansion B to accommodate REZs	Expansions were considered in the PSCR for VNI 6 (Expansion B) and VNI 7 (Expansion A) with new transmission lines to facilitate generation hosting capacity at Central North Victoria (V6) REZ and Murray River (V2) REZ respectively.	The VNI 6 option put forward in the PSCR and 2020 ISP was ruled out in the 2022 ISP, as outlined above. It has therefore no longer been considered in this RIT-T. Studies during the PADR revealed that VNI West already meets the required REZ hosting capacity without the need for an expansion. However, an expansion may be considered in the future to harness additional renewables.
VNI 8	This option was included in the VNI West PSCR as a lower cost 330 kV alternative to VNI West (via Kerang). It consisted of 330 kV double-circuit lines from a new terminal station north of Ballarat via Kerang and Darlington Point to Wagga, and avoiding Bendigo.	Due to the reduced transfer capacity and REZ hosting capacity, this option delivered fewer net market benefits compared to VNI 6 and VNI 7, and was therefore not progressed as a preferred candidate ISP option. It has therefore no longer been considered in this RIT-T. Moreover, AVP and Transgrid note that regardless of whether the line is built at 3300 kV or 500 kV, switching stations are required and so 330 kV does not allow for material cost savings.

A. ERM Power p 3.
B. AEMO, 2020 ISP Appendix 3. Network Investments, July 2020, p 66.
C. AEMO, Draft 2022 ISP, Appendix 5. Network investments, December 2021, p. 24.
D. AEMO, Draft 2022 ISP, Appendix 5. Network investments, December 2021, pp. 19-20.
E. AEMO, 2020 ISP Appendix 3. Network Investments, July 2020, p 66. The majority of the options discussed and discounted in the 2020 ISP were not options that were included in the earlier PSCR, but have been included here for completeness.
F. AEMO, 2020 ISP Appendix 3. Network Investments, July 2020, p 66.
G. The PSCR included two variations of this option that either bypass Shepparton (VNI 6-V1) or go via both Bendigo and Shepparton (VNI 6-V2). Specifically, VNI 6-V1 involved new 500 kV transmission lines from a new terminal station north of Ballarat – Bendigo – Wagga; VNI 6-V2 involved new 500 kV transmission lines from a new station north of Ballarat – Bendigo – Shepparton – Wagga.

7 Ensuring the robustness of the analysis

Each of the credible options has been assessed across three scenarios, consistent with the recommendations of the 2022 ISP. The scenarios, and assumptions feeding into the scenarios, are sourced directly from those used in the 2022 ISP.

Under the actionable ISP framework, the ISP directs the use of specific scenarios (and their weightings) for each RIT-T.

These scenarios reflect different assumptions about future market development, the pace of the energy transition and other uncertain but potentially material factors that are expected to affect the relative market benefits of the options being considered. The different scenarios investigated test the robustness of the RIT-T credible options to different assumptions about how the energy sector may develop in the future.

7.1 The assessment considers three 'reasonable scenarios'

The RIT-T is focused on identifying the top ranked credible option that maximises expected net benefits. However, uncertainty exists around aspects such as how quickly the energy transformation will occur, the scale of future distributed energy resource uptake, and the level of demand growth as other sectors electrify or consider use of alternate zero-emission fuels.

To deal with this uncertainty, the actionable ISP framework requires AEMO to direct the use of specific scenarios for each RIT-T. The costs and market benefits for each credible option are estimated across these scenarios and then weighted based on the likelihood-based weightings identified in the ISP for each scenario to determine a weighted ('expected') net benefit[121]. It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options have been assessed under three scenarios as part of this PADR assessment, which align with the three scenarios recommended for the VNI West RIT-T in the 2022 ISP. Table 8 below summarises the specific key variables that influence the net benefits of the options under each of the three scenarios considered.

Table 8 PADR modelled scenario's key drivers input parameters

Key drivers input parameters	*Step change*	*Progressive Change*	*Hydrogen Superpower*
Underlying consumption	2021 *Electricity Statement of Opportunities* (ESOO) (2022 ISP) – *Step Change*	2021 ESOO (2022 ISP) – *Progressive Change*	2021 ESOO (2022 ISP) – *Hydrogen Superpower*
New entrant capital cost for wind, solar photovoltaic (solar PV), single-axis tracking (SAT), open cycle gas turbine (OCGT), combined-cycle gas turbine (CCGT), pumped storage hydropower	2021 Inputs and Assumptions Workbook – *Step Change*	2021 Inputs and Assumptions Workbook – *Progressive Change*	2021 Inputs and Assumptions Workbook – *Hydrogen Superpower*

121 AER, *Cost Benefit Analysis Guidelines*, August 2020, p. 53.

Key drivers input parameters	Step change	Progressive Change	Hydrogen Superpower
(PSH), and large-scale storage			
Retirements of coal-fired power stations	2021 Inputs and Assumptions Workbook – step change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	2021 Inputs and Assumptions Workbook – *Progressive Change*: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030	2021 Inputs and Assumptions Workbook – *Hydrogen Superpower*: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives
Gas fuel cost	2021 Inputs and Assumptions Workbook – *Step Change*: Lewis Grey Advisory 2020, *Step Change*	2021 Inputs and Assumptions Workbook - *Progressive Change*: Lewis Grey Advisory 2020, central	2021 Inputs and Assumptions Workbook – *Hydrogen Superpower*: Lewis Grey Advisory 2020, step change
Coal fuel cost	2021 Inputs and Assumptions Workbook – Step Change: Wood Mackenzie, *Step Change*	2021 Inputs and Assumptions Workbook – *Progressive Change*: Wood Mackenzie, central	2021 Inputs and Assumptions Workbook – *Hydrogen Superpower*: Wood Mackenzie, step change
NEM carbon budget to achieve 2050 emissions levels	2021 Inputs and Assumptions Workbook – *Step Change*: 891 Mt CO2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook – *Progressive Change*: 932 Mt CO2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook – *Hydrogen Superpower*: 453 Mt CO2-e 2023-24 to 2050-51
Victoria Renewable Energy Target (VRET)	40% renewable energy by 2025 and 50% renewable energy by 2030 VRET 2 including 600 MW of renewable capacity by 2025		
Queensland Renewable Energy Target (QRET)	50% by 2030		
Tasmanian Renewable Energy Target (TRET)	2021 ISP: 200% renewable generation by 2040		
New South Wales Electricity Infrastructure Roadmap	2021 Inputs and Assumptions Workbook: 12 gigawatts (GW) New South Wales Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the 2022 ISP 2 GW of long duration storage (8 hrs or more) by 2029-30		
Project EnergyConnect	2022 ISP – Project EnergyConnect commissioned by July 2025[A]		
Western Renewables Link	2022 Draft ISP – Western Victoria upgrade commissioned by November 2025[B]		
HumeLink[C]	2022 ISP – *Step Change*: HumeLink commissioned by July 2028	2022 ISP – *Progressive Change*: HumeLink commissioned by July 2035	2022 ISP – *Hydrogen Superpower*: HumeLink commissioned by July 2027
Marinus Link	2022 ISP –1st cable commissioned by July 2029 and 2nd cable by July 2031		
Victoria – New South Wales Interconnector Upgrade (VNI Minor)	2022 ISP – VNI Minor commissioned by December 2022		
Queensland – New South Wales Interconnector Upgrade (QNI Minor)	2022 ISP – QNI Minor commissioned by July 2022		
QNI Connect	2022 ISP – *Step Change*: QNI Connect commissioned by July 2032	2022 ISP – *Progressive Change*: QNI Connect commissioned by July 2036	2022 ISP – *Hydrogen Superpower*: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030
VNI West	2022 ISP – *Step Change*: VNI West commissioned by July 2031	2022 ISP – *Progressive Change*: VNI West commissioned by July 2038	2022 ISP – *Hydrogen Superpower*: VNI West commissioned by July 2030
Victorian SIPS	2022 ISP – 300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021.		
New-England REZ Transmission	2022 ISP – *Step Change*: New England REZ Transmission Link commissioned by July 2027, New	2022 ISP – *Progressive Change*: New England REZ Transmission Link	2022 ISP – *Hydrogen Superpower*: New England REZ Transmission Link commissioned

Key drivers input parameters	*Step change*	*Progressive Change*	*Hydrogen Superpower*
	England REZ Extension commissioned by July 2035	commissioned by July 2027, New England REZ Extension commissioned by July 2038	by July 2027, New England REZ Extension commissioned by July 2031, and stage 3 by July 2042
Snowy 2.0	2021 Inputs and Assumptions Workbook – Snowy 2.0 is commissioned by December 2026		

A. The 2022 ISP delivery date for Project EnergyConnect was updated to July 2026. The modelling for the 2022 ISP and this PADR assumed a delivery date of July 2025. As this link is still expected to be developed ahead of VNI West, the change in timing has minimal impact on this PADR.
B. The 2022 ISP delivery date for the Western Renewables Link was updated to July 2026. As this link is still expected to be developed ahead of VNI West, the change in timing has minimal impact on this PADR
C. This RIT-T modelled HumeLink as commissioned according to the ISP scenario timings, which are ahead of the VNI West timings across all scenarios.

AVP and Transgrid note that the Victorian Government's offshore wind policy, announced in March 2022, could not to be reflected in the wholesale market modelling for this PADR due to the timeframes for finalising inputs. However, based on the offshore wind sensitivity analysis included in the final 2022 ISP, Transgrid and AVP do not consider that it will have a material impact on the estimated benefits of VNI West. In fact, the sensitivity undertaken on the *Step Change* scenario finds that the expected benefits of VNI West increase by approximately $67 million[122] when the offshore wind targets specified in the Victorian Government's Directions Paper, together with greater capital cost reductions for offshore wind generation based on CSIRO's draft 2021-22 GenCost Report[123], are assumed.

7.2 Weighting the reasonable scenarios

AEMO specifies in the 2022 ISP that the scenario weightings in Table 9 should be applied in the RIT-T for VNI West[124].

Table 9 Scenario probability weightings

Scenario	2022 ISP probability weighting
Step Change	52%
Progressive Change	30%
Hydrogen Superpower	18%

While the above weightings were applied to weight the estimated market benefits and identify the preferred option across scenarios, AVP and Transgrid have also carefully considered the results in each scenario in Section 9 to better understand how differences in the future 'states of the world' can impact the benefits of the two options.

7.3 Sensitivity analysis

In addition to the scenario analysis, AVP and Transgrid have also considered the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity testing. The range of factors tested as part of the sensitivity analysis in this PADR are:

- Removing the power flow controllers from VNI West.

[122] AEMO, 2022 ISP, Appendix 6. Cost benefit analysis, June 2022, P. 78.

[123] CSIRO, *Gen Cost 2021-22 Consultation Draft*, December 2021. At https://doi.org/10.25919/k4xp-7n26.

[124] AEMO, 2022 ISP, June 2022, p. 75. AEMO has not included the *Slow Change* scenario because it carries a low likelihood (4%) and the optimal timing is similar to the *Progressive Change* scenario.

- Changes in the capital costs of the credible options.
- Alternate commercial discount rate assumptions.

The results of the sensitivity tests are discussed in Section 9.5.

AVP and Transgrid have also estimated the 'threshold value' for key variables beyond which the outcome of the analysis would change. As there are inter-dependencies between many of these variables, the threshold values are indicative only and assume all else being equal. It should also be noted that, as mentioned elsewhere in this PADR, some of the benefits of the two options have been underestimated but further analysis to assess these additional benefits is not currently considered warranted as it would not materially change the PADR assessment. Should capital costs or commercial discount rates approach the estimated threshold values, these benefits may need to be revisited.

8 Estimating the costs and market benefits

Significant work has been undertaken since the PSCR to develop more accurate cost estimates for the options, including in light of the various social impacts and network topology considerations raised in submissions.

Seven categories of market benefit under the RIT-T are considered material for this RIT-T and have been estimated as part of the PADR assessment. Wholesale market modelling has been used to estimate these categories of market benefits.

8.1 Cost estimates

The cost estimates presented in this PADR have been undertaken on a jurisdictional basis, with AVP responsible for the estimates of the part of the options located in Victoria and Transgrid responsible for the estimates of the part of the options located in New South Wales.

Both AVP and Transgrid have estimated the following seven different categories of cost for each option:

- Early works.
- Substation works.
- Line works.
- Battery construction costs (for the VTL option).
- Costs of modular power flow controllers.
- Property/land access/easements.
- Biodiversity offset costs.

The level of granularity in the revised cost estimates is considered consistent with that in the AEMO Transmission Cost Database[125] that has been extensively consulted on in 2021 for the 2022 ISP.

The overall cost estimates for each option are broken out across these categories in Table 4, Section 6.1. Appendix A3 provides additional detail in response to submissions on the cost estimating methodologies applied for each of these categories (for both the Victoria and New South Wales components).

The revised cost estimates are considered to an accuracy of ±30%[126], which AVP and Transgrid consider to be 'class 4' estimates[127].

[125] See https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan.

[126] Accuracy bands have been derived statistically, such that 80% of project estimates should fall within these limits. It is therefore expected that, across a large sample of projects, approximately 20% of them will fall outside of these bands.

[127] AEMO, *2021 Transmission Cost Report,* August 2021, p. 12.

AVP and Transgrid consider the cost estimates used in this PADR to be at a higher level of accuracy than estimates developed using the AEMO Transmission Cost Database's cost estimating tool, since they reflect additional detailed costing undertaken by AVP and Transgrid in the context of this project.

AVP and Transgrid note that the level of accuracy is consistent with current industry practice for this stage of the investment process[128]. The level of cost accuracy for the investments will be further refined and developed if the project is justified under the RIT-T process and proceeds through to the CPA and contestable procurement stages. As outlined in Section , as part of the CPA process, Transgrid will seek a 'feedback loop' confirmation from AEMO in line with the new actionable ISP framework ahead of lodging a CPA for investment in VNI West. As with HumeLink, Transgrid is intending to submit two CPAs to the AER in relation to the regulatory cost recovery for the project.

Cost estimates include an allowance for known and unknown risks, that will or could arise during the further development and execution of this project including:

- Known risks – where risks are identified but the ultimate value of the risk is not known:
  - Land access / easements / compulsory acquisition.
  - Cultural heritage.
  - Environmental offset risks (biodiversity).
  - Waste disposal/contamination.
  - Geotechnical makeup along the route (ground conditions for footings).
  - Outage restrictions.
  - Weather delays.
- Unknown risks – where the risk has not been identified but industry experience indicates these could occur:
  - Productivity and labour cost.
  - Plant procurement cost.
  - Project overheads.
  - Scope and technology.

The VNI West cost estimates used in this PADR differ from that presented in the 2022 ISP by approximately $300 million due to a change in the level of line cost contingency provisioned in the Victorian component of the project to account for remediation of social and environmental concerns. As outlined in Section 5.1.2, this recognises that, based on recent experience, some level of route diversion, tower redesign, or screening may be required beyond that anticipated and included in the Victorian component of the estimate presented in 2022 ISP. This provision does not anticipate undergrounding costs. If partial undergrounding is required, a greater level of contingency would be needed.

It is expected through completion of early works that greater certainty on risk will be obtained through stakeholder engagement, site investigations and design development.

[128] The 2021 AEMO *Transmission Cost Report* states that future ISP projects typically have costs estimated to be 'Class 5B or 5a', while he PADR and PACR are typically at 'Class 4 or Class 3'. See AEMO, *2021 Transmission Cost Report*, August 2021, pp. 12-13.

8.2 Expected market benefits from expanding transfer capacity

As outlined in Section 8.3, the key benefits expected from increasing transfer capacity are driven by anticipated changes in wholesale market outcomes going forward as Australia transitions to net zero by 2050.

For each scenario described in Section 7.1, the RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the credible options in place, separately. The 'state of the world' is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity and timing of future generation and storage investment as well as unrelated future transmission investment (for example, that is required to connect REZs).

The specific categories of market benefit under the RIT-T that have been modelled as part of this PADR are:

- Changes in costs for parties, other than the RIT-T proponent (that is, changes in investment in generation and storage capital and fixed and variable operating and maintenance costs).
- Changes in fuel consumption in the NEM arising through different patterns of generation dispatch.
- Differences in REZ transmission costs.
- Changes in involuntary load curtailment.
- Changes in voluntary load curtailment.
- Changes in network losses.
- Option value.

A wholesale market modelling approach similar to the approach used in the 2022 ISP has been applied to estimate the market benefits associated with each credible option included in this RIT-T assessment[129]. The approach taken to estimating each of these market benefits is outlined below and discussed in greater detail in the accompanying market modelling report.

One key difference between the ISP and this RIT-T assessment is the choice of counterfactual used to assess the market benefits of each option. The counterfactual 'base case' in the ISP is one without any new transmission development, whereas in this RIT-T assessment, other major transmission projects identified in the ISP optimal development path are assumed to be developed in all 'states of the world', including the counterfactual. This is discussed further in section 4.5.

8.2.1 Changes in costs for other parties in the NEM

This category of market benefit is expected where credible options result in different investment patterns of generators and large-scale storage across the NEM, compared to the base case.

In particular, the market modelling finds that there are large amounts of avoided new generation and storage investment compared to the base case. As shown in Section 9, these avoided or deferred costs associated with generation and storage are the most material category of market benefit estimated for both options across the

[129] The RIT-T requires that in estimating the magnitude of market benefits, a market dispatch modelling methodology must be used, unless the TNSP(s) can provide reasons why this methodology is not relevant. See AER, *Regulatory Investment Test for Transmission*, August 2020, p. 8.

three scenarios[130]. While this class of market benefits captures avoided or deferred capital costs, as well as operating and maintenance costs (both variable and fixed), the market modelling finds that it is made up primarily of avoided or deferred capital costs.

8.2.2 Changes in fuel consumption in the NEM

This category of market benefit is expected where credible options result in different patterns of generation and storage dispatch across the NEM, compared to the base case.

In particular, the primary effects of expanding transfer capacity come from enabling demand centres to be supplied by lower cost generation than can be expected if no upgrade is undertaken. The market modelling finds that new renewable generation avoids the need for gas-fired generation in Victoria to operate as frequently, noting that this generation still plays a crucial rule in firming and providing essential power system services to maintain grid security and stability over the outlook period. As outlined in Section 9, this is the second largest category of benefit estimated for both options across the three scenarios[131].

8.2.3 Differences in REZ transmission costs

This benefit category relates to the costs of intra-regional transmission investment associated with the development of REZs that could be avoided if a credible option is pursued.

AEMO has identified a number of candidate REZs in various NEM jurisdictions as part of the ISP and has included allowances for transmission augmentations that it considers would be required to develop those REZs. The credible options being considered in this RIT-T can allow development of some of these REZs without the need for additional intra-regional transmission investment (or less of it), leading to REZ transmission cost savings.

8.2.4 Changes in involuntary load curtailment

Increasing the transfer capacity between New South Wales and Victoria allows existing generation and storage in each state to be utilised more efficiently to meet demand. It also provides greater access to renewable generation and the deep storage of Snowy 2.0 which, in combination, will meet demand throughout the year once ageing coal plant retires. This will provide greater reliability for each state by reducing the potential for supply shortages and the consequent risk of involuntary load shedding.

This market benefit involves quantifying the impact of changes in involuntary load shedding associated with the implementation of each credible option via the time-sequential modelling component of the market modelling. Specifically, the modelling estimates the MWh of unserved energy (USE) in each trading interval over the modelling period, and then applies a Value of Customer Reliability (VCR, expressed in $/MWh) to quantify the estimated value of avoided USE for each option. AVP and Transgrid have adopted the AER's most recent assumptions for the VCR for the purposes of this assessment, as in the 2021 IASR.

This category of market benefit has been found to be relatively small within the market modelling as new generation and storage capacity is built in all future states of the world, including the base case, if required to meet demand and a reserve margin used as a proxy for the reliability standard. There is therefore no material

[130] The one exception to this is for Option 1 under the *Step Change* scenario, where this category of market benefits is effectively the same size as the avoided fuel costs benefits. For all other scenarios, for both options, this category is the most material category of market benefit estimated.

[131] The one exception to this is for Option 1 under the *Step Change* scenario, where this category of market benefits is effectively the same size as the benefits from avoided or deferred, costs associated with generation and storage. For all other scenarios, for both options, this category is the second most material category of market benefit estimated.

difference in the quantity of involuntary load shedding between each option and the base case, under each of the scenarios. Many of the reliability benefits of VNI West are therefore reflected through capital deferral, with less investment in dispatchable capacity required to maintain reliability in an efficient manner.

8.2.5 Changes in voluntary load curtailment

Voluntary load curtailment is when customers agree to reduce their load once wholesale prices in the NEM reach a certain threshold. Customers usually receive a payment for agreeing to reduce load in these circumstances. Where the implementation of a credible option affects wholesale price outcomes, and in particular results in wholesale prices reaching higher levels in some trading intervals than in the base case, this may have an impact on the extent of voluntary load curtailment.

This class of market benefit has also been found to be relatively low within the market modelling, reflecting that the level of voluntary load curtailment currently present in the NEM is not significant.

8.2.6 Changes in network losses

The time-sequential market modelling has taken into account the change in network losses that may be expected to occur as a result of the implementation of each of the credible options, compared with the level of network losses which would occur in the base case, for each scenario.

The benefit of changes to network losses is captured within the wholesale market modelling of dispatch cost benefits of avoided fuel costs and changes to voluntary and involuntary load shedding.

The reduction in network losses between the base case and the options is not considered material for the options considered in this PADR, since any effect on losses will come primarily from the VNI West component (which features in both options).

8.2.7 Option value

The modelling in this PADR estimates the option value associated with VNI West as part of the scenario analysis, which is in line with the AER's CBA Guidelines[132]. Specifically, while the timing of Stage 1 is the same across the scenarios, the timing for Stage 2 differs depending on scenario (as outlined in Table 5, Section 6.2), which captures the option value associated with the second stage[133] as identified in the 2022 ISP.

AVP and Transgrid do not consider VNI West to exhibit additional flexibility outside of the Stage 1/Stage 2 flexibility and so do not consider there to be any additional option value associated with VNI West and so also do not consider additional, detailed real options analysis warranted.

8.3 Wholesale market modelling has been used to estimate market benefits

AVP and Transgrid engaged EY to undertake the wholesale market modelling to assess the market benefits expected to arise under each of the credible options and scenarios.

[132] AER, *Cost Benefit Analysis Guidelines*, August 2020, pp, p. 37-42.

[133] Note while this RIT-T assessment did not separately quantify the option value associated with the second stage, the 2022 ISP assessment showed that staging VNI West delivers an additional $40 million of net market benefits over proceeding now with VNI West without any staging

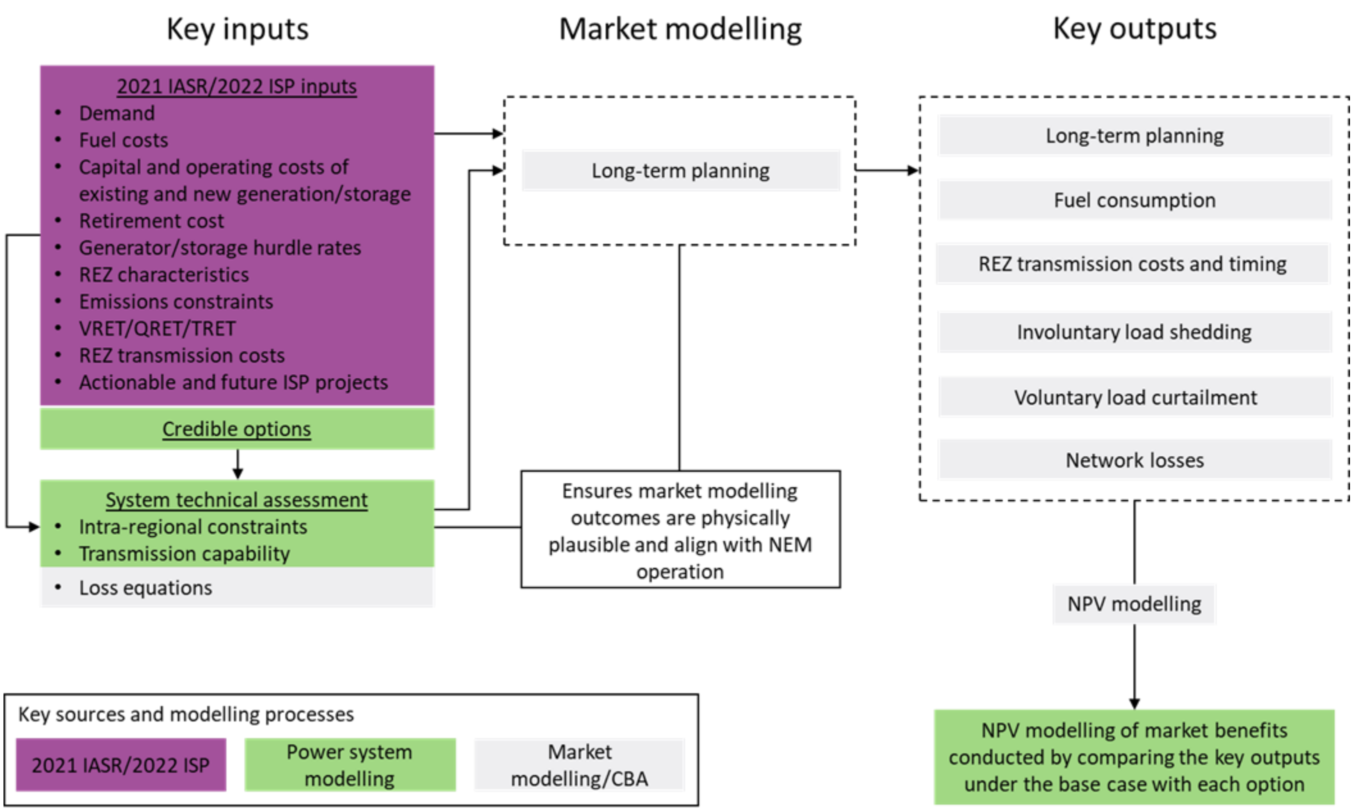
EY applied a linear optimisation model and performed hourly, time-sequential, long-term modelling for the NEM to estimate categories of wholesale market benefits expected under each of the options. Specifically, EY undertook long-term investment planning to identify the least-cost generation, storage and unrelated transmission infrastructure development schedule, while meeting demand requirements, policy objectives, and technical generator and network performance limitations.

AVP and Transgrid have undertaken a detailed System Technical Assessment, which evaluates the power system behaviour and performance under the credible options and ensures market modelling outcomes are physically plausible, follow the operation of the NEM, and that the power system impacts of the credible options are appropriately represented. This assessment serves as an input to the wholesale market modelling EY has undertaken.

Similar studies are undertaken in developing the ISP.

Figure 6 illustrates the interactions between the key modelling studies and where the key assumptions have been sourced.

Figure 6 Overview of the market modelling process and methodologies



8.3.1 Applying ISP parameters

Under the actionable ISP framework, the ISP identifies the major transmission investments (including enhanced interconnection) and development opportunities (generation, storage and DER) that are key to underpinning the energy transition (the 'optimal development path') and makes key network and non-network projects 'actionable' by triggering a requirement on the relevant jurisdictional planners to prepare a PADR under the RIT-T. As part of this framework, the AER has published CBA Guidelines to make the ISP actionable that seek to minimise duplication between the ISP and RIT-Ts.

In doing so, several changes to the RIT-T process have been introduced, including guidance as to how the RIT-T proponent must apply the ISP parameter. In accordance with the CBA Guidelines, unless there is a demonstrable reason not to, the RIT-T proponent is required to:

- adopt the scenarios that AEMO has specified as relevant to that RIT-T application, and the inputs and assumptions from the most recent IASR,
- adopt the likelihood weightings to apply to the scenarios, as specified in the most recent ISP,
- include other actionable ISP projects in all states of the world (including the base case), and
- treat non-actionable ISP projects (that is, future ISP projects and ISP development opportunities) as modelled projects that can vary by scenario or state of the world as per the ISP.

The two sub-sections below provide additional detail on the wholesale market modelling EY has undertaken as part of this PADR assessment, including how these ISP parameters have been adopted. The accompanying market modelling report provides additional detail on these modelling studies, as well as the key modelling assumptions and approach adopted more generally.

8.3.2 Long-term Investment Planning

The function of the Long-term Investment Planning is to develop generation, storage and REZ transmission infrastructure forecasts and generator retirement schedules over the assessment period for each of the credible options and base cases. This is similar to the ISP Detailed Long Term (DLT) modelling.

This modelling determines the least-cost development schedule for each credible option and scenario drawing on the IASR assumptions regarding demand, supply, distributed energy resource uptake, network and other underlying assumptions such as carbon budget constraints over the assessment period.

The generation, storage and REZ transmission infrastructure development schedule resulting from the Long-term Investment Planning is determined such that:

- It economically meets hourly regional and system-wide demand while accounting for network losses.
- It builds sufficient generation and storage capacity to meet demand when economic, while considering potential generator forced outages. The cost of unserved energy (USE) is balanced with the cost of new generation investment to supply any potential shortfall.
- Generators' technical specifications such as minimum stable loading and maximum capacity are observed.
- Notional interconnector flows do not breach technical limits and interconnector losses are accounted for.
- Hydro storage levels and battery storage state of charge do not breach maximum and minimum values and cyclic losses are accounted for.
- New generation capacity is connected to locations in the network where it is most economical from a whole of system cost.
- Scenario-specific NEM-wide emissions constraints are adhered to.
- NEM-wide and state-wide renewable energy targets are met.
- Generator maintenance outages are scheduled to represent planned generator outages.

- Energy-limited generators such as Tasmanian hydro-electric generators and the Snowy Hydro scheme are scheduled to minimise system costs.
- The overall system cost spanning the whole outlook period is optimised while adhering to constraints.

Rather than use the ISP development opportunities and future ISP projects relating to REZ development, directly from the 2022 ISP, these infrastructure development forecasts and retirement schedules are redetermined using market development modelling for each state of the world for consistency across the options assessed and the states of the world with and without the options in place. This is necessary to isolate the market outcome changes due to the options under assessment from any market outcomes changes due to differences in the modelling tools and approaches used in the ISP and this RIT-T.

Coal-fired generation is treated as dispatchable between its minimum load and its maximum load in the modelling. Coal-fired 'must run' generation is dispatched whenever available at least at its minimum load. No seasonal mothballing or two-shifting is assumed. Open cycle gas turbines are assumed to operate with no minimum load; they start and are dispatched for a minimum of one hour whenever the cost of supply is at or above their short-run marginal cost. The accompanying market modelling report provides additional detail on how these constraints as well as early coal retirements have been reflected in the analysis.

The long-term investment planning model ensures there is sufficient dispatchable capacity in each region to meet peak demand in the region, plus a reserve level sufficient to allow for generation or transmission contingences which can occur at any time, regardless of the present dispatch conditions. This reserve level acts as a proxy for the reliability standard of no more than 0.002% expected unserved energy in any region, in any given year.

Due to load diversity and sharing of reserve across the NEM, the reserve to be carried is minimised at times of peak, and provided from the lowest cost providers of reserve including allowing for each region to contribute to its neighbours reserve requirements through interconnectors.

The market modelling report accompanying this PADR provides additional detail on the assumptions and methodological approaches adopted in the long-term investment planning, including necessary model simplifications, sub-regional modelling and how new capacity has been modelled.

8.3.3 Modelling of intra-regional constraints

The wholesale market simulations include a simplified representation of intra-regional constraints in addition to the inter-regional transfer limits.

Key intra-regional transmission constraints in New South Wales have been captured by splitting New South Wales into zones (Northern New South Wales – NNS, Central New South Wales – NCEN, Canberra – CAN and South West New South Wales – SWNSW), and explicitly modelling intra-regional connectors across boundaries or cut-sets between these zones. Bi-directional flow limits and dynamic loss equations were formulated for each intra-regional connector. This is similar to the ISP, with the exception of South New South Wales being split into CAN and SWNSW in this PADR. In addition, to more accurately capture the benefit of the options being considered, the CAN and SWNSW zones in New South Wales as well as Victoria were split into further nodes and an equivalent network was developed to accommodate the DC power flow with all transmission lines, both existing and defined in the options, explicitly modelled by its impedance and thermal limits.

Inter- and intra- regional constraints, such as Victoria to New South Wales and Snowy area constraints, are overlaid on the modelled DC power flow. For further information on the network model and intra and inter-regional constraints, please refer to the accompanying market modelling report.

8.4 Cost benefit analysis parameters adopted

The RIT-T analysis in this PADR spans a 27-year assessment period from 2021-22 to 2047-48. This period has been adopted to capture both the period of costs incurred for the early works (which commenced in 2021-22 for the New South Wales component) and 25 years of wholesale market modelling (covering 2023-24 to 2047-48)[134].

This assessment horizon includes the shorter-, medium- and longer-term drivers of the benefits associated with the credible options including renewable energy targets, consumption of assumed carbon budgets, retirement of brown coal generators in Victoria, and retirement of black coal generators in New South Wales and Queensland.

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes a terminal value to capture costs and benefits over the remaining asset life as required by the CBA Guidelines. This ensures that the costs of long-lived options over the assessment period are appropriately captured, and that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life.

The discounted cash flow analysis and terminal value approach used for this RIT-T differs from that used in the 2022 ISP. The ISP, undertaking a whole-of-system optimisation, converts the capital investment in generation, storage and transmission infrastructure into an equivalent annual annuity to allow like-for-like comparison on assets with different economic lives and different commissioning dates. The annuity approach begins to recognise costs once an asset is commissioned, and inherently makes an assumption that costs (i.e. annualised capital costs and ongoing operating costs) and benefits are neutral for the remaining economic lives of assets beyond the modelling horizon.

This RIT-T, which is assessing and ranking credible options to address an identified need, incorporates explicit build profiles, as well as the early works expenditure profile, for the two options assessed such that cash flows during construction and early works are recognised as they occur. This approach incorporates the total capital expenditure in the discounted cash flow and then uses a terminal value to capture the ongoing operating costs and benefits expected over the remaining asset life.

The terminal value can be calculated by using a forecast of the benefit streams expected over the remaining life of the assets, or by relating to the remaining cost of the asset at the end of the assessment period. For this RIT-T , the terminal values are calculated as the undepreciated value of capital costs at the end of the analysis period and can be interpreted as a conservative estimate for benefits (net of operating costs) arising after the analysis period.

AVP and TransGrid consider that the assumption that benefits over the remaining life of the assets will exceed the undepreciated capital costs and the ongoing operating costs is reasonable based on the market benefits assessment undertaken. The market benefits assessment projected that market benefits net of operating costs in the last five years of the assessment period stabilised at around $280 million per annum for Option 1 on a weighted basis. Using a benefit extrapolation approach would result in a terminal value approximately 1.6 times the terminal value used (in present value terms).

The CBA Guidelines requires the discount rate used in the NPV analysis to be the commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. A central discount rate of 5.50% (real, pre-tax) has been used in the NPV analysis, consistent with the RIT-T requirements and the 2021 IASR. The cost benefit assessment has included sensitivity testing with a lower bound discount rate of 2.30%

[134] Note this assessment period is slightly shorter than the 2022 ISP, which extended to 2050-51.

equal to the latest AER Final Decision for a TNSP's regulatory proposal at the time of preparing this PADR[135], and an upper bound discount rate of 7.50% (consistent with the upper bound in the latest IASR).

The Long-term Investment Planning adopts the same commercial discount rates as used in the NPV discounting calculation in the cost benefit analysis. This is consistent with the approach taken in the 2022 ISP.

8.5 Classes of market benefit not considered material

The NER require that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the TNSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option[136].

The PSCR outlined how all categories of market benefit identified in the RIT-T have the potential to be material with the exception of changes in ancillary services costs, competition benefits, and the negative of any penalty payable for not meeting the renewable energy target. AVP and Transgrid have not changed the PSCR view regarding the immateriality of these potential sources of market benefit.

AVP and Transgrid note that, in October 2021, as part of preparing the 2022 ISP, AEMO commenced industry consultation in relation to potentially amending the *ISP Methodology* and 2021 IASR in relation to competition benefits. The purpose of this consultation was to engage stakeholders on how competition benefits could be calculated in the ISP, if this class of benefit is deemed to be material to the selection of the optimal development path and can be calculated with a proportionate level of certainty[137]. Following stakeholder consultation, AEMO concluded that competition benefits would not be routinely calculated in the ISP[138] and, in the 2022 ISP, stated that competition benefits have not been included in the assessment of the optimal development path due to the significant uncertainty surrounding key assumptions that would need to be made in the calculation of these benefits[139].

AVP and Transgrid note also that AEMO will not be considering competition benefits as part of the 'feedback loop' process subsequent to this RIT-T, consistent with the 2022 ISP framework,[140] ahead of Transgrid lodging a CPA for investment in VNI West.

Notwithstanding this, AVP and Transgrid have undertaken a preliminary, order-of-magnitude assessment of competition benefits as part of the PADR analysis, to further determine whether this benefit category is expected to be material to the outcome of this RIT-T. These investigations have concluded that competition benefits are not expected to be material for this RIT-T and hence have not been included in the NPV assessment in this PADR.

[135] This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM. See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powerlink-determination-2022%E2%80%9327/final-decision.

[136] NER clause 5.16.1(c)(6).

[137] AEMO, *Competition benefits in the Integrated System Plan – Consultation Summary Report*, December 2021, p. 4.

[138] See https://aemo.com.au/consultations/current-and-closed-consultations/competition-benefits-in-the-isp.

[139] AEMO, Draft 2022 ISP, December 2021, p. 83.

[140] AEMO, Draft 2022 ISP, December 2021, p. 83.

9 Net present value

This section presents the results of the NPV assessment of the credible options. This assessment finds that VNI West is expected to provide a positive net market benefit of $687 million on a weighted basis across the three ISP scenarios investigated. It also finds that combining VNI West with a VTL would not increase the overall expected net benefit.

The accompanying EY market modelling report provides additional detail in terms of the modelled wholesale market impacts for each option, under each scenario.

9.1 *Step Change* scenario

The *Step Change* scenario is summarised by AEMO as 'rapid consumer-led transformation of the energy sector and coordinated economy-wide action'. The *Step Change* scenario moves quickly initially to fulfilling Australia's net zero policy commitments and, rather than building momentum over time (as in the *Progressive Change* scenario), sees a consistently fast-paced transition from fossil fuel to renewable energy in the NEM. By 2050, this scenario assumes that most consumers rely on electricity for heating and transport, and the global manufacture of internal-combustion vehicles has all but ceased.

Under these assumptions, Option 1 – VNI West – is found to be the top-ranked option with estimated net market benefits of approximately $884 million. Option 2 – VTL plus VNI West – is found to have net market benefits of approximately $789 million (11% less than Option 1). This indicates that the additional cost of the VTL components under the *Step Change* scenario is not outweighed by the additional expected market benefits.

Figure 7 shows the composition of estimated net benefits for each option under the *Step Change* scenario. The key findings from the assessment of each option under this scenario are:

- Avoided/deferred generation and storage capital costs and avoided fuel costs are the primary sources of benefit for both options (contributing similar levels of gross benefits and, together making up 93% of the estimated gross market benefits for the options).
- Avoided/deferred generation and storage capital costs (the yellow sections of each bar in Figure 7) are primarily driven by deferred/avoided investment of large-scale storage and gas as well as some early deferral of predominantly wind capacity, though more wind and solar capacity is expected by the end of the study period.
  - Both options enable increased resource sharing and better Snowy 2.0 utilisation between Victoria and the other mainland regions that allows increased zero emissions generation in the NEM after commissioning. The forecast increase in high quality renewable generation after the option is commissioned allows for a less frenetic transition away from coal in the 2020s without violating the emissions constraint. This ultimately drives the deferral of some capital investment in wind resources that would otherwise have been needed to help maintain energy supplies following the coal closure, until after the commissioning of VNI West.

- From the mid-2030s, both options are forecast to avoid gas generation build in Victoria due to the increased transfer limits between Victoria and New South Wales, enabling more generation (including generation exported and stored in Snowy 2.0 at other times) to be imported to Victoria to meet demand when required.
- The VTL in Option 2 contributes to additional deferred/avoided investment in large-scale storage, wind and solar capacity, due to earlier increases in the transfer limits between Victoria and New South Wales, allowing for an increase in utilisation of existing generation capacity.

- Avoided fuel costs (the blue-green sections of each bar in Figure 7) arise primarily from avoided gas generation in Victoria after VNI West is commissioned through to the end of the modelling horizon.
  - Much of the gas generation is replaced by increased wind, solar and storage generation in all mainland NEM regions, with the majority of increased generation coming from New South Wales. While not an explicit consideration allowed in the RIT-T, this has an added advantage of delinking energy prices in the NEM from the volatility of international fossil fuel markets.
  - Gas still plays a critical role as coal-fired generation retires, as a complement to battery and pumped hydro generation in periods of peak demand, and during long 'dark and still' weather periods. It will also provide essential power system services to maintain grid security and stability
  - Avoided fuel costs are found to be essentially the same across the two options; that is, the VTL in Option 2 is not expected to result in material additional avoided fuel costs.
- REZ transmission cost savings (the orange sections of each bar in Figure 7) are driven by VNI West allowing builds in REZs with increased transmission capacity such as Murray River (V2) and Western Victoria (V3) to replace/defer REZ transmission expansion in REZs such as Central North Victoria (V6) and Ovens Murray (V1).

Figure 7 Breakdown of estimated net benefits under the *Step Change* scenario

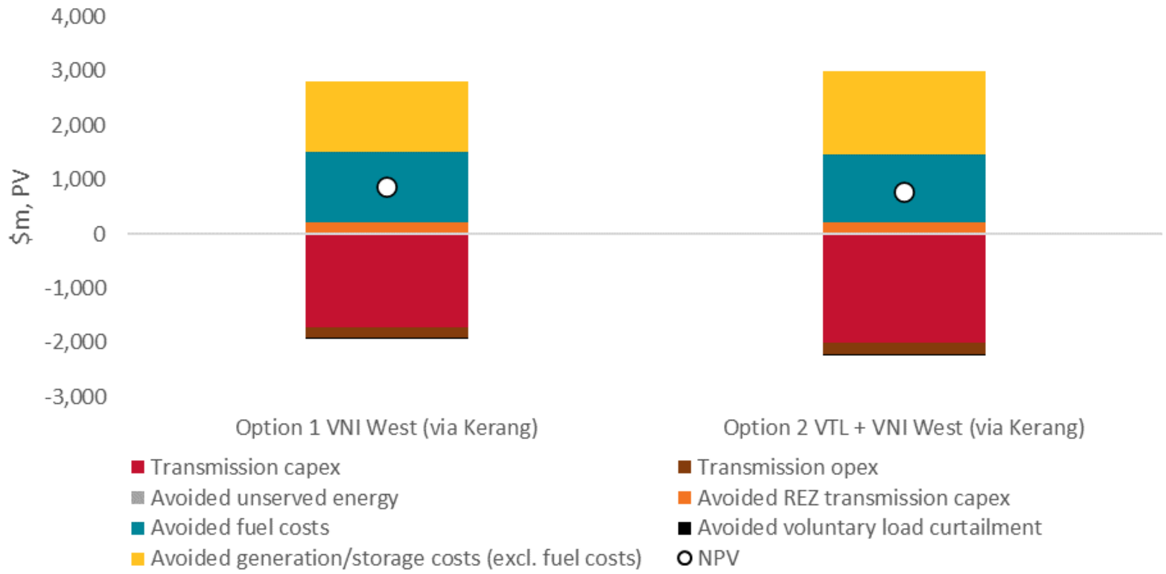


Figure 8 below presents the estimated cumulative expected gross benefits for Option 1 for each year of the assessment period under the *Step Change* scenario[141,142,143]. It shows that, while benefits from avoided/deferred generation costs accrue straightaway, benefits from avoided fuel consumption begin accruing from commissioning in 2031-32 and accrue steadily from there.

Figure 8 Breakdown of cumulative gross benefits for Option 1 under the *Step Change* scenario

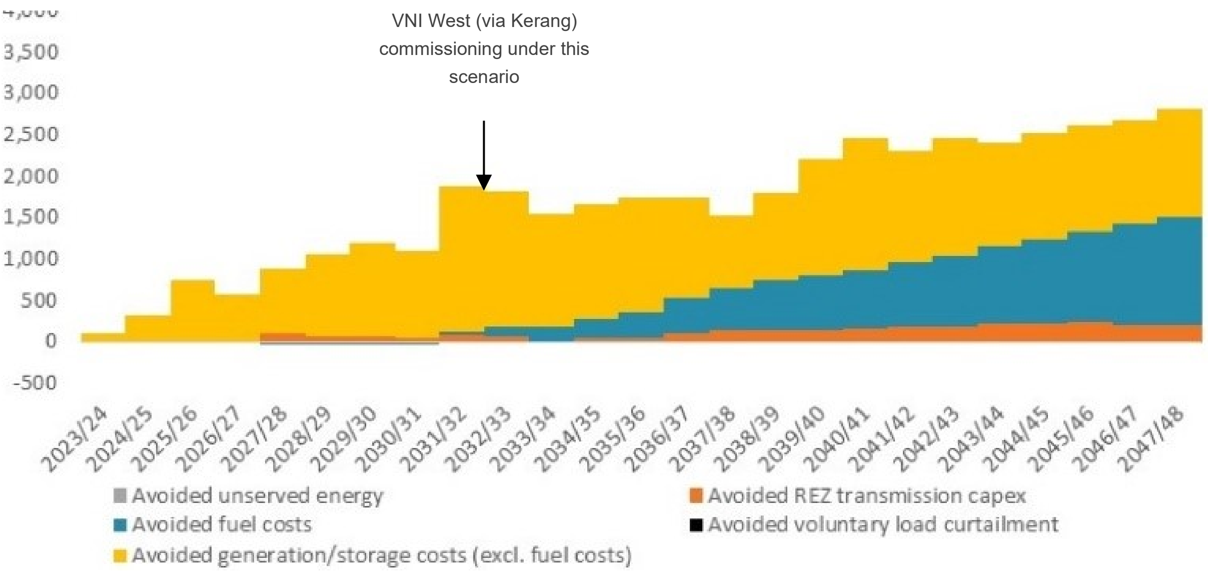


Figure 9 summarises the difference in generation and storage capacity modelled for Option 1 (in GW), compared to the base case[144]; that is, what is found to be driving the avoided or deferred costs associated with generation and storage benefit.

With VNI West there is less solar generation build overall up to the end of the 2030s, with VNI West harnessing more high quality solar generation (higher capacity factor) in the Murry River REZ, and less solar generation development in Ovens Murray, Central North Victoria and Gippsland REZs in Victoria, as well as less in Queenland (Fitzroy REZ) and South Australia (Riverland REZ).

[141] This figure only presents the annual breakdown of estimated gross benefits for the preferred option. The separately released spreadsheet presents an annual breakdown of costs and benefits for both options. Since this figure shows the cumulative gross benefits in present value terms, the height of the bar in the last year equates to the gross benefits for Option 1 shown in Figure 8, above. This applies to all figures of this type in this PADR document.

[142] While all generator and storage capital costs have been included in the market modelling on an annualised basis, this chart, and all charts of this nature in the PADR, present the entire capital costs of these plant in the year avoided to highlight the timing of the expected market benefits. This is purely a presentational choice to assist with relaying the timing of expected benefits (for example, coincident with when thermal plant retire, or transmission augmentations are commissioned) and does not affect the overall estimated net benefit of the options.

[143] A decrease in the cumulative gross benefits between years in this chart is due to that year having greater costs with Option 1 than the base case, for example due to deferred investment occurring in that year that would have otherwise occurred earlier under the base case. This applies for this chart, and all charts of this type in the PADR.

[144] For the avoidance of doubt, all figures of this type in the PADR are showing the differences in cumulative capacity *across the NEM*, compared to the base case.

Figure 9 Difference in cumulative capacity build with Option 1, compared to the base case, under the *Step Change* scenario

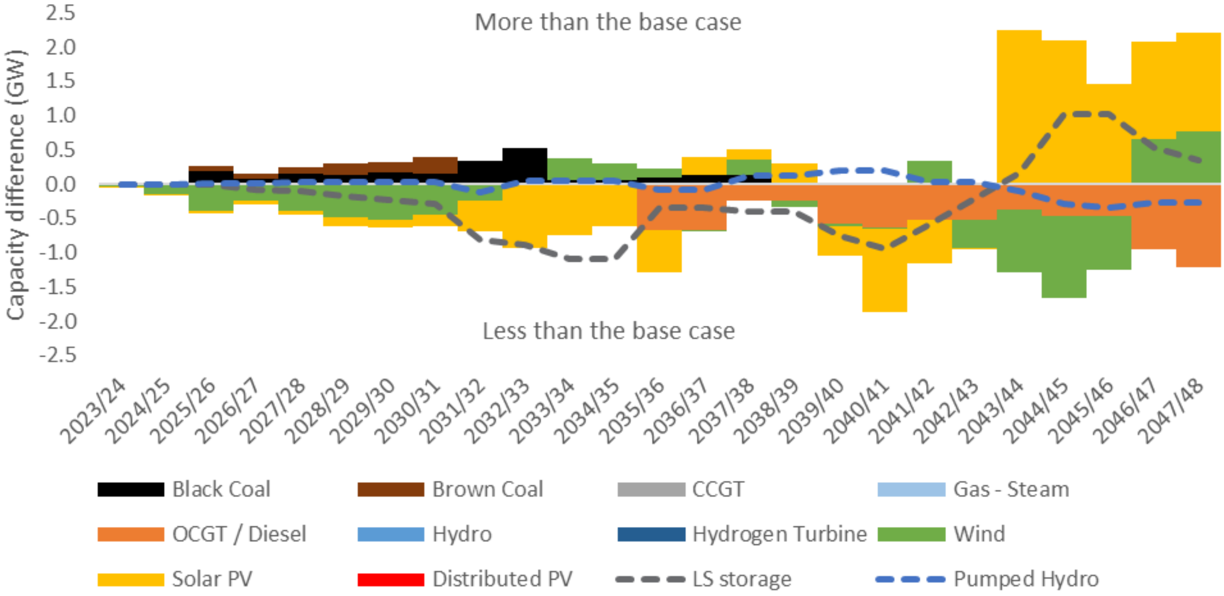
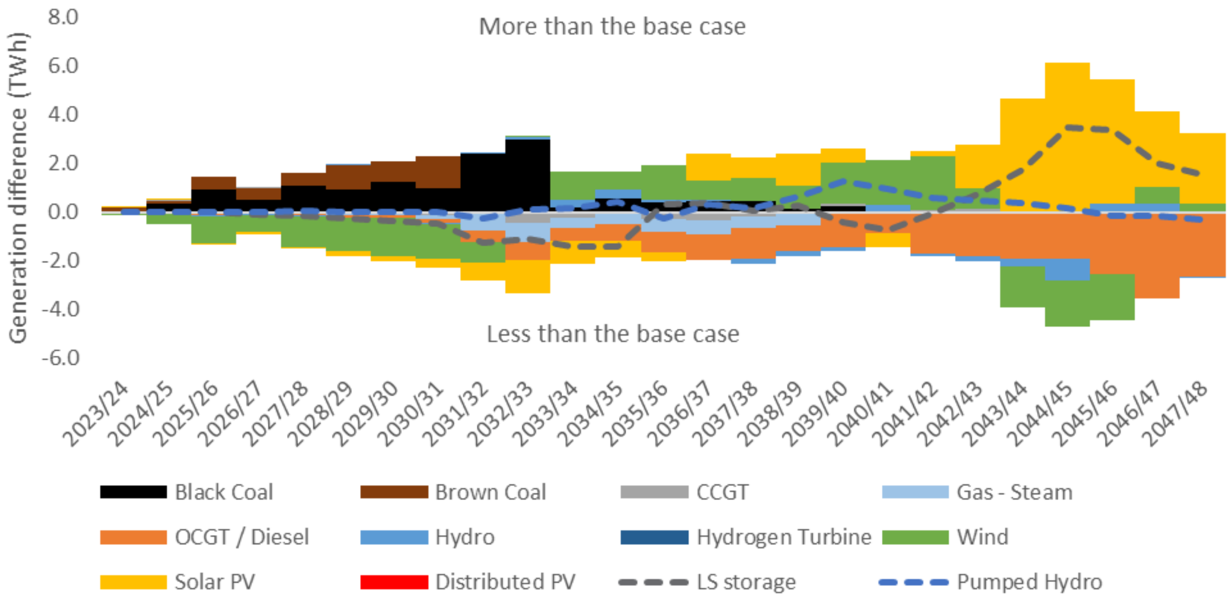


Figure 10 summarises the difference in generation and storage output modelled for Option 1 (in terawatt hours (TWh)), compared to the base case; that is, what is found to be driving the avoided fuel cost benefit. The reduction in OCGT/diesel utilisation is clearly evident.

Figure 10 Difference in output with Option 1, compared to the base case, under the *Step Change* scenario



9.2 *Progressive Change* scenario

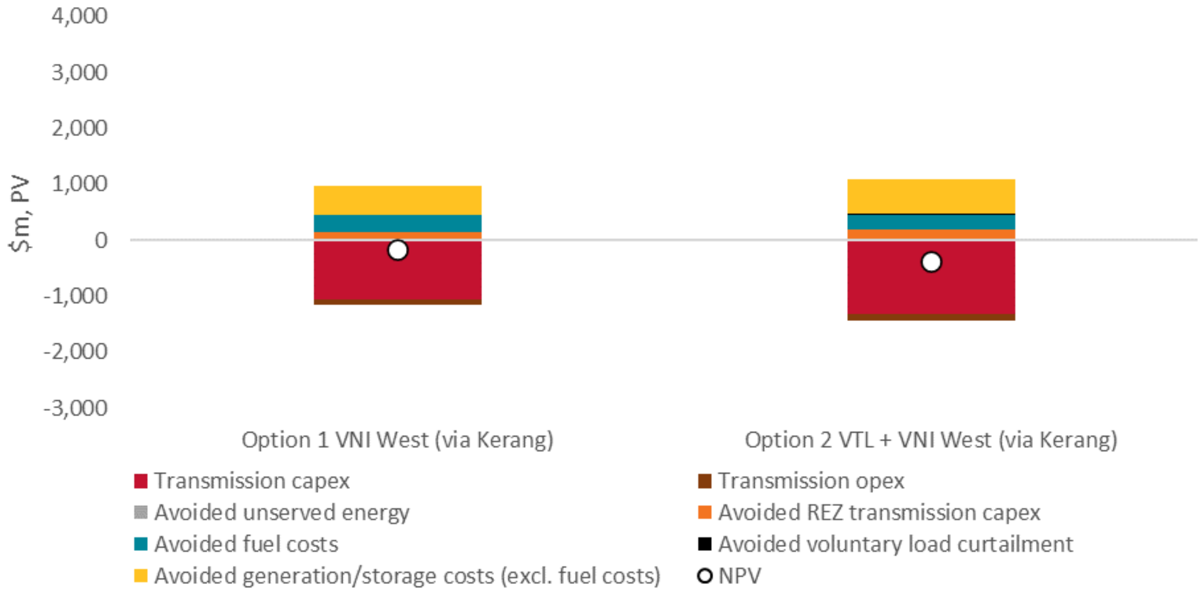
The *Progressive Change* scenario is summarised by AEMO as 'pursuing an economy-wide net zero emissions 2050 target progressively, ratcheting up emissions reduction goals over time'. The *Progressive Change* scenario delivers the decarbonisation objectives of Australia's Emissions Reduction Plan, with a progressive build-up of momentum ending with significant reductions in emissions from the 2040s to meet net zero by 2050. Electric vehicles become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses.

Under these assumptions, both options are found to have a negative net market benefit (that is, a net market cost), even with a delayed commissioning to 2038-39, and therefore to be less preferred to the 'do nothing' base case, although the size of the negative net benefit for Option 1 is relatively low. Option 1 is found to have estimated net costs of $169 million. Option 2 has larger estimated net costs of $361 million. Even though these benefits are net negative, with early works having been undertaken immediately, the modelling still indicates that consumers would subsequently be better off with the project built by 2038 than not at all.

The finding that Option 1 is expected to result in a marginal net market cost differs from the 2022 ISP, where it was found to deliver a net market benefit in all scenarios. This is due to a difference in how Victorian capital costs are captured between the two assessments, specifically, adoption of a build profile including early works expenditure (this RIT-T) versus inclusion as annualised costs (ISP)) as well as the higher Victorian capital costs used. Section 8.4 and Appendix A3 explains these two differences (respectively) in more detail, which are not material to the outcome of the assessment.

Figure 11 shows the composition of estimated net benefits for each option under the *Progressive Change* scenario.

Figure 11 Breakdown of estimated net benefits under the *Progressive Change* scenario



The key findings from the assessment of each option under the *Progressive Change* scenario are:

- Avoided/deferred generation and storage capital costs (the yellow sections of each bar in Figure 11) are the largest source of benefit for both options (making up between 53% and 56% of the estimated gross market benefits for the options):

  - Similar to the *Step Change* scenario, deferring and avoiding large-scale storage and gas are the major drivers for these benefits. In addition, it is expected that both options result in replacing some solar with wind capacity by the end of the study period.
  - While significant new investment is forecast by the end of modelling period, benefits in this scenario are significantly lower than the *Step Change* scenario due to underlying assumptions, particularly a less restrictive carbon budget assumption. This is projected to result in slower coal withdrawals and less renewable and large-scale storage investments in the NEM, which reduces the need for more interconnection through Option 1.
  - Option 2 has lower benefits under this scenario than the *Step Change* scenario as the additional transfer capacity provided by the addition of the VTL has little value when there is less need for new generation development even in the base case.
- Avoided fuel costs (the blue-green sections of each bar in Figure 11) are the second largest source of benefit for both options (making up between 26% and 30% of the estimated gross market benefits for the options):
  - These benefits arise primarily from reduced gas generation in Victoria, which is mostly replaced by increased wind and solar generation in New South Wales and Victoria.
  - Fuel cost savings are mostly due to reductions in OCGT in Victoria (because Option 1 improves sharing of capacity between regions), with the reduction in CCGT generation also contributing to this in the last year of the assessment period.
  - Option 2 provides no additional fuel cost savings relative to Option 1 under this scenario.
- REZ transmission cost savings (shown by the orange sections of each bar in Figure 11 above) are driven by VNI West allowing builds in REZs with free transmission capacity such as Murray River (V2) and Western Victoria (V3) to replace/defer REZ transmission expansion in REZs such northern Queensland REZs (and their relevant group REZ transmission constraints), and to a lesser extent in other REZs such as Cooma Monaro, Central Highlands, Ovens Murray and Central North Victoria.

Figure 12 below presents the estimated cumulative expected gross benefits for Option 1 for each year of the assessment period under the *Progressive Change* scenario.

Figure 12 Breakdown of cumulative gross benefits for Option 1 under the *Progressive Change* scenario

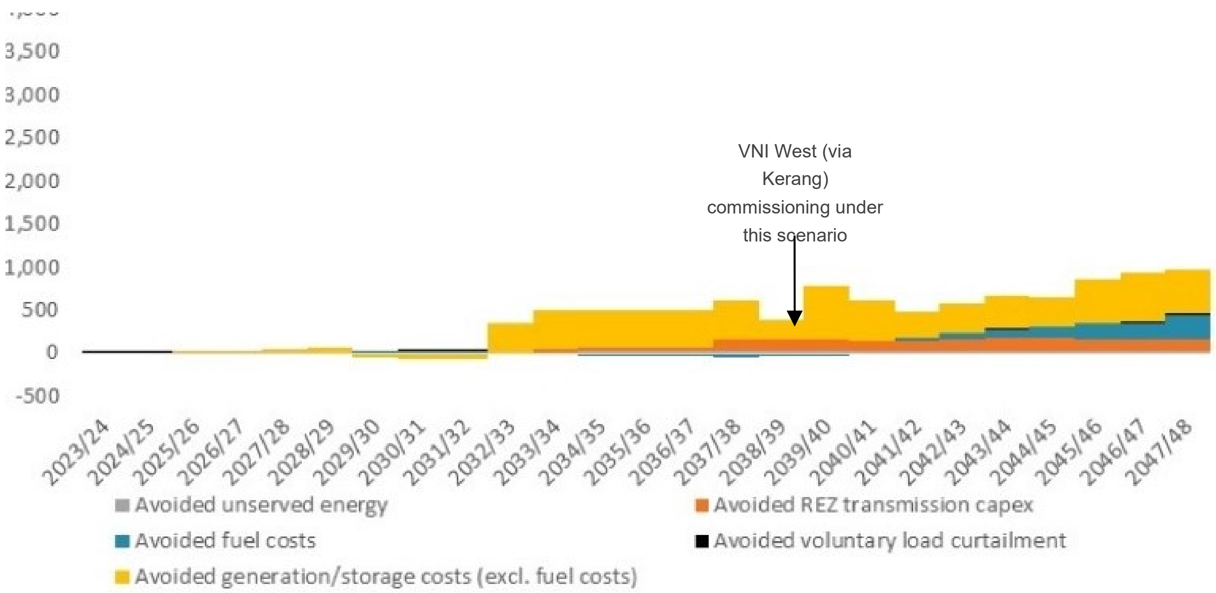


Figure 12 shows that, while benefits from avoided/deferred generation and storage costs begin accruing from the mid-2030s, benefits from avoided fuel consumption begin accruing in the 2040s.

Figure 13 summarises the difference in generation and storage capacity modelled for Option 1 (in GW), compared to the base case; that is, what is found to be driving the avoided or deferred costs associated with generation and storage benefit.

Figure 13 Difference in cumulative capacity built with Option 1, compared to the base case, under the *Progressive Change* scenario

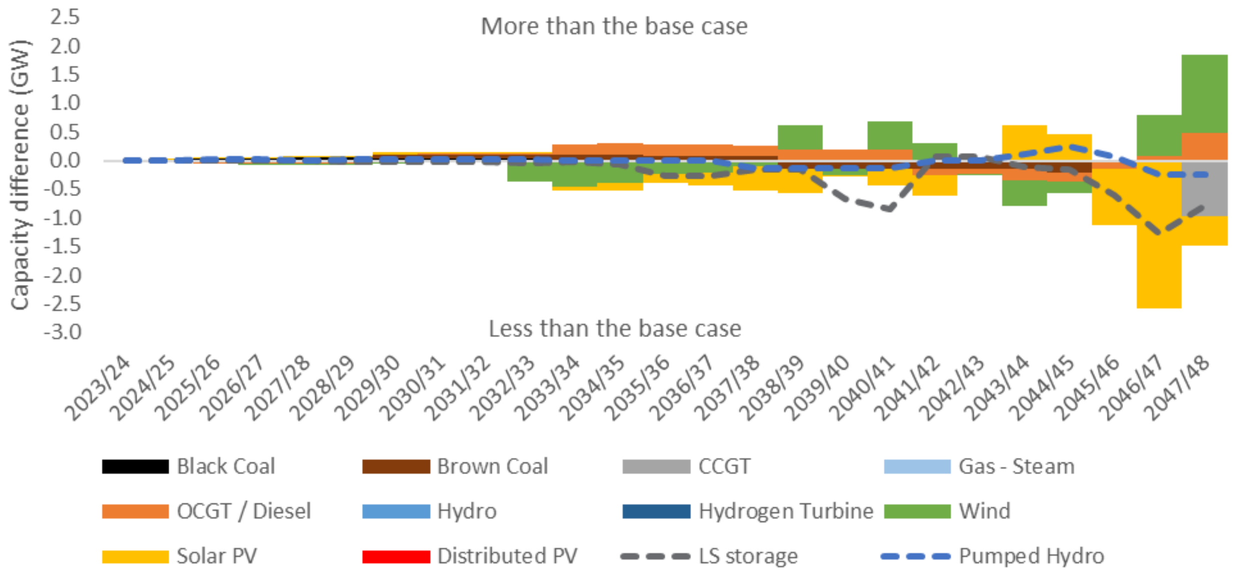
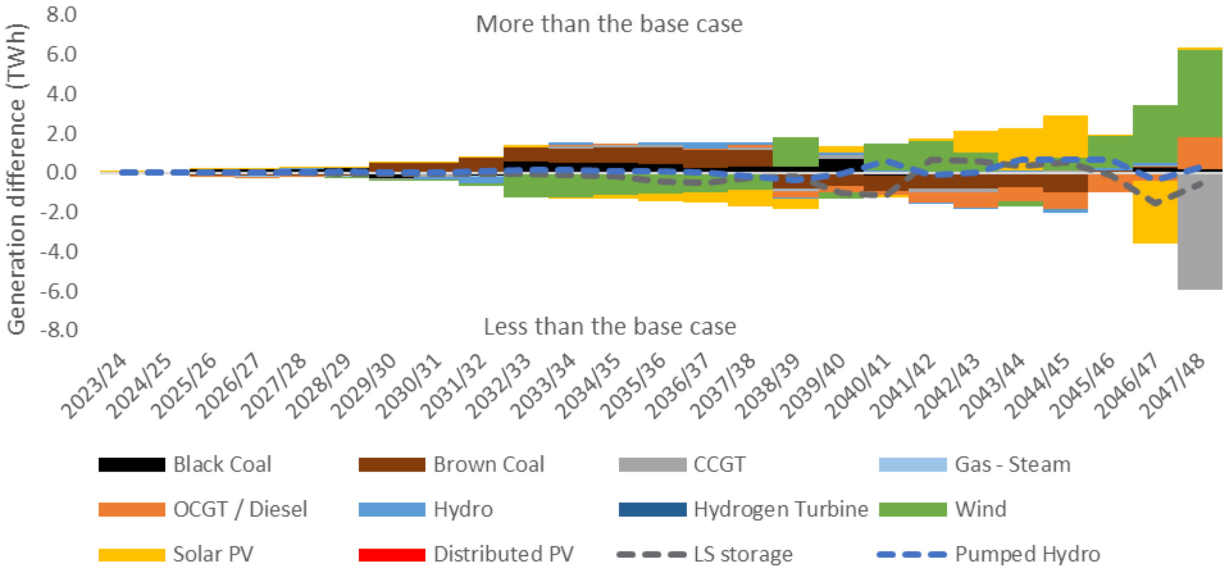


Figure 14 summarises the difference in generation and storage output modelled for Option 1 (in TWh), compared to the base case; that is, what is found to be driving the avoided fuel cost benefit.

Figure 14 Differences in output with Option 1, compared to the base case, under the *Progressive Change* scenario



9.3 *Hydrogen Superpower* scenario

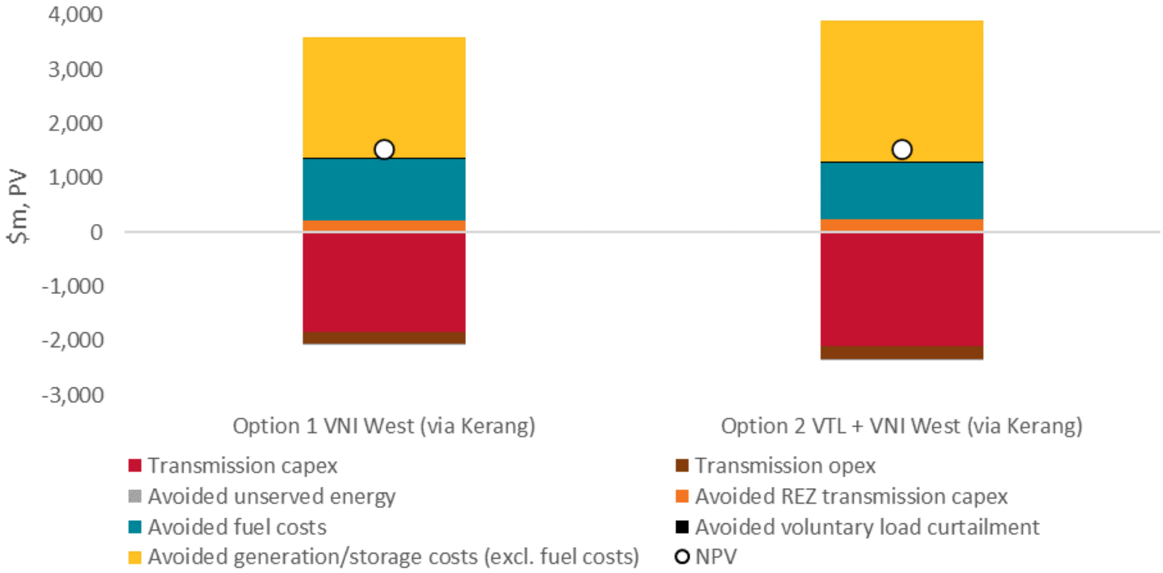
The *Hydrogen Superpower* scenario is summarised as 'strong global action and significant technological breakthroughs'. While the two previous scenarios assume nearly the same doubling of demand for electricity to support industry decarbonisation, the *Hydrogen Superpower* scenario nearly quadruples NEM energy consumption to support a hydrogen export industry. In this scenario, households with gas connections progressively switch to a hydrogen-gas blend before appliance upgrades achieve 100% hydrogen use[145].

Under these assumptions, Option 1 and Option 2 are found to have equivalent net benefits. Specifically, Option 1 has estimated net market benefits of $1,543 million, while Option 2 has net benefits of $1,539 million (only 0.29% less than Option 1). The marginally lower net benefits for Option 2 indicate that the additional cost of the VTL components is not outweighed by the additional expected benefits they provide under the *Hydrogen Superpower* scenario (but are closer than in the other two scenarios).

Figure 15 shows the composition of estimated net benefits for each option under the *Hydrogen Superpower* scenario.

[145] AEMO, 2022 ISP, June 2022, p. 31.

Figure 15 Breakdown of estimated net benefits under the *Hydrogen Superpower* scenario



The key findings from the assessment of each option under the *Hydrogen Superpower* scenario are:

- Avoided/deferred generation and storage capital costs (the yellow sections of each bar in Figure 15) are the largest source of benefit for both options (making up between 62% and 67% of the estimated gross market benefits for the options):
  - These benefits are primarily driven by avoided solar generation in lower quality areas, hydrogen turbines and large-scale storage capacity (mostly in Victoria). The reduced generation from these avoided investments in Victoria is primarily met by increased wind generation both in New South Wales and Victoria. VNI West effectively allows for more technological diversity which delivers associated efficiencies. The timing of this avoided capacity occurs mostly after the assumed commissioning of Option 1 in 2030-31.
  - The significant demand forecast in this scenario results in much more solar generation capacity in the base case (with more spilled energy) compared to in the *Step Change* scenario. While more solar is built in Murray River REZ, and more solar in Western Victoria under both options, generally significantly less solar is built across the NEM, including in Wagga Wagga and North West New South Wales and North East Tasmania. This solar is replaced by wind in New South Wales, including in the Central West Orana REZ, and in Western Victoria REZ.
  - The earlier timing of increased transfer capacity between Victoria and New South Wales in Option 2 compared to Option 1 provides more market benefits earlier by more efficiently utilising existing generation assets in New South Wales, deferring some investment in wind generation that would otherwise be needed in Victoria as more brown coal generation withdraws from service.
- Avoided fuel costs (the blue-green sections of each bar in Figure 15) are the second largest source of benefit for both options (making up between 27% and 31% of the estimated gross market benefits for the options):
  - These benefits arise primarily from reduced fuel costs from the avoided hydrogen turbine capacity and generation in Victoria from the mid-2030s onwards.
  - There are minor changes to fuel cost savings with the VTL component (Option 2) relative to VNI West alone (Option 1).

- REZ transmission cost savings (shown by the orange sections of each bar in Figure 15 above) are driven by VNI West harnessing generation and capacity diversity between Victoria and northern states such as New South Wales and Queensland, as well as more builds in REZs with free transmission capacity such as Murray River (V2) and Western Victoria (V3) to replace/defer REZ transmission expansion in REZs such as North West New South Wales (N1), North East Tasmania (T1), Central North Victoria (V6) and Ovens Murray (V1).

Figure 16 below presents the estimated cumulative expected gross benefits for Option 1 for each year of the assessment period under the *Hydrogen Superpower* scenario. It shows that, while benefits from avoided/deferred generation and storage costs accrue straightaway (due to more accelerated coal withdrawals in the base case), benefits from avoided fuel consumption begin accruing from when Option 1 is commissioned and increase steadily from there.

Figure 16 Breakdown of cumulative gross benefits for Option 1 under the *Hydrogen Superpower* scenario

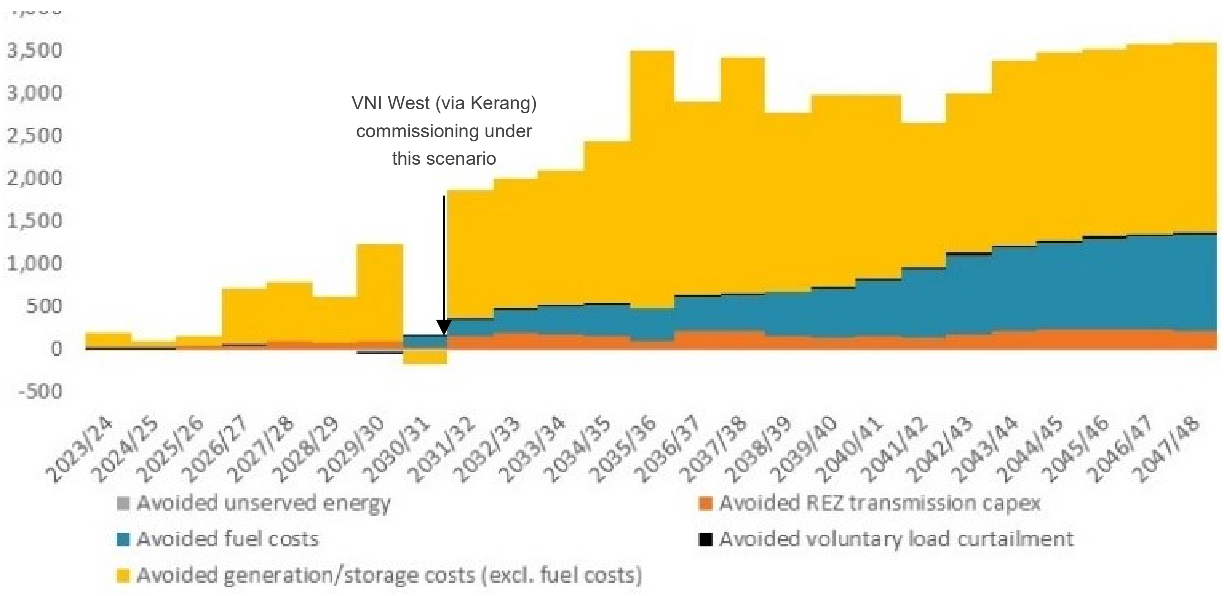


Figure 17 summarises the difference in generation and storage capacity modelled for Option 1 (in GW), compared to the base case; that is, what is found to be driving the avoided or deferred costs associated with generation and storage benefit.

Figure 17 Difference in cumulative capacity built with Option 1, compared to the base case, under the *Hydrogen Superpower* scenario

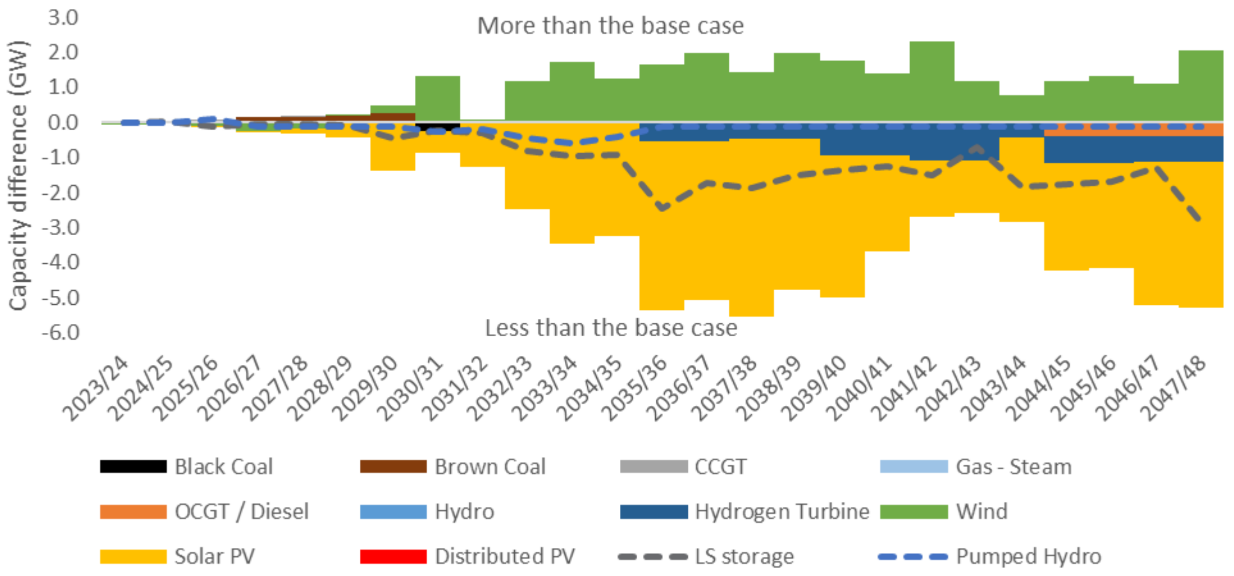
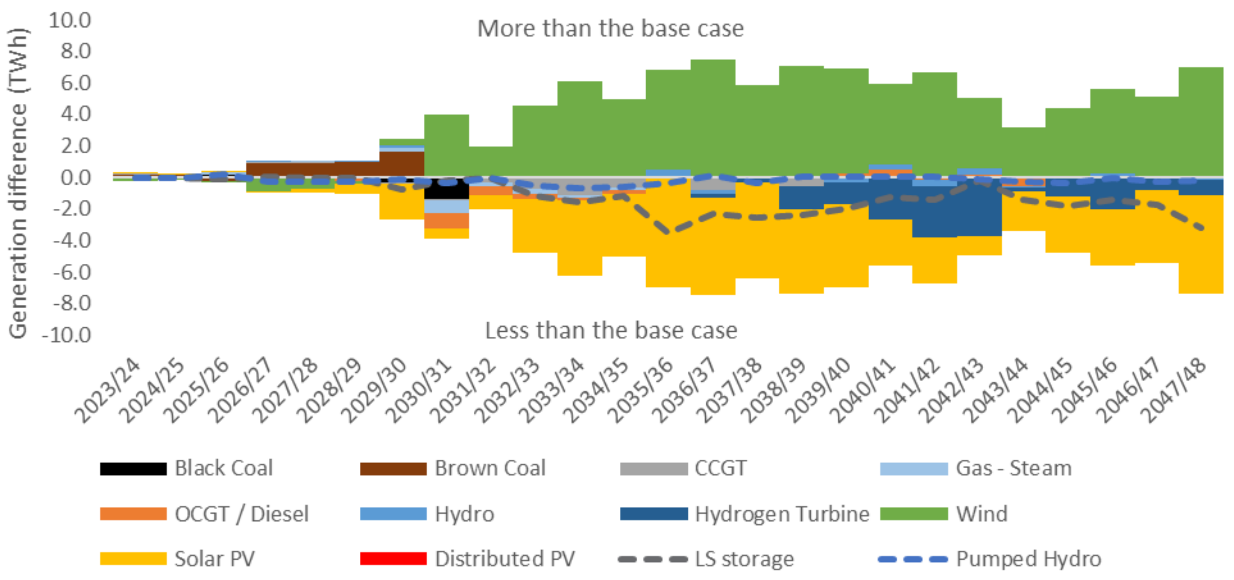


Figure 18 summarises the difference in generation and storage output modelled for Option 1 (in TWh), compared to the base case; that is, what is found to be driving the avoided fuel cost benefit.

Figure 18 Difference in output with Option 1, compared to the base case, under the *Hydrogen Superpower* scenario



9.4 Weighted results

Comparing the credible options across the scenarios investigated (and discussed above), both options are expected to achieve their highest market benefits in the *Hydrogen Superpower* scenario, and their lowest market benefits in the modelled *Progressive Change* scenario.

- VNI West offers greater geographical and technical diversity, which is of more value the faster the pace of decarbonisation (as weather-dependent generation starts to dominate), and the larger the increase in electrical load via electrification.
- VNI West allows a more manageable transition to net zero under scenarios with carbon budgets to limit global temperature increase to below 2°C. Without VNI West, an even more frenetic pace would be needed with more coal closures in next decade and increased challenges around ability to maintain reliability, security and affordability.
- VNI West reduces reliance on gas generation, which is needed more in scenarios with rapid decarbonisation and without the addition of flexible electricity demand for hydrogen production.
- Option 2 is most beneficial in scenarios with a rapid need for new development to replace coal generation as the VTL component can be built earlier (by July 2026).

Table 10 shows the estimated net benefits for each of the credible options weighted across the scenarios investigated. Under the weighted outcome, Option 1 is the top-ranked option and is found to result in an estimated net benefit of $687 million overall. Option 2 is ranked second with an estimated net benefit of $579 million, 16% less than Option 1.

Table 10 Summary of the estimated net benefits, weighted across the scenarios

	Option 1 VNI West	Option 2 VNI West + VTL
Weighted NPV ($ million)	687	579

9.5 Sensitivity analysis

In addition to the scenario analysis, AVP and Transgrid have considered the robustness of the outcome of the cost benefit analysis through undertaking a number of sensitivity tests. These tests all relate to the weighted net benefits, unless stated otherwise.

The range of factors tested as part of the sensitivity analysis in this PADR are:

- Removing the power flow controllers from VNI West.
- Changes in the capital costs of the credible options.
- Alternate commercial discount rate assumptions.

These sensitivity tests are summarised in Table 11 and briefly discussed in the sections below.

Table 11 Impact of changes in capital costs and discount rates, weighted NPVs ($ million)

	Network capex		VTL battery capex		Discount rate	
	30% higher	**30% lower**	**30% higher**	**30% lower**	**High (7.5%)**	**Low (1.96%)**
Option 1 VNI West	$225	$1,148	$687	$687	$292	$2,174
Option 2 VNI West + VTL	$118	$1,039	$494	$663	$203	$2,019
Removal of modular power flow controllers						
Option 1 with MPFC	$884					
Option 1 without MPFC	$684					

9.5.1 Removing the modular power flow controllers

AVP and Transgrid investigated a sensitivity that excludes the modular power flow controllers from VNI West under the *Step Change* scenario. This tested whether the inclusion of the modular power flow controllers within the scope of VNI West is net beneficial to this option.

The net benefits for Option 1 under the *Step Change* scenario decrease from $884 million under the core results (shown in Section 9.1 above) to $684 million when the power flow controllers are removed from the analysis. This represents a $200 million decrease in net benefits, which confirms that the expected additional gross wholesale market benefits expected from the power flow controllers exceeds their costs.

9.5.2 Changes in the capital costs of the credible options

AVP and Transgrid tested the sensitivity of the results to the underlying capital costs of the credible options.

Option 1 remains the top-ranked option regardless of whether network related capital costs are 30% higher or 30% lower, or the assumed VTL battery related capital costs are 30% higher or lower. Under all four sensitivities, Option 1 continues to deliver positive expected net market benefits for consumers.

Looking at Option 1 on its own, 'boundary testing' finds that the central estimates of network related capital costs (including land costs) would need to increase by around 45% in order for Option 1 to have negative net benefits on a weighted basis. AVP and Transgrid do not consider this likely given that cost estimates have been prepared to a ±30% degree of accuracy.

AVP and Transgrid also found that the VTL battery related capital costs would need to be 38% lower for Option 2 to have the same net benefits as Option 1 (while holding the network capital costs of Option 1 and Option 2 constant).

9.5.3 Alternate commercial discount rate assumptions

The robustness of the calculated net market benefits to variations in discount rates was tested using:

- A high discount rate of 7.50%.
- A low discount rate of 2.30%.

Under the high discount rate sensitivity, Option 1's net benefits decrease by $394 million, or about 43%, on a weighted basis compared to net benefits under a central discount rate of 5.50%. Under the low discount rate sensitivity, the net benefits of Option 1 increase by $1,277 million, or 186%, compared to net benefits under the central discount rate.

Under both sensitivities, Option 1 remains the top-ranked option and continues to deliver positive net market benefits to consumers. A discount rate of greater than 51% would be required for Option 2 to be preferred over Option 1. AVP and Transgrid consider this to be unrealistic.

'Boundary testing' finds that the discount rate would need to be greater than 10.3% for Option 1 to have negative net benefits. This discount rate is marginally above the highest discount rate of 10% suggested by AEMO in the 2022 ISP[146].

[146] AEMO, 2022 ISP, June 2022, p. 91.

10 Conclusion

VNI West, referred to as 'Option 1' in this PADR, is found to be the preferred option at this stage of the RIT-T.

It is found to have significantly greater net market benefits on a weighted basis across the three scenarios investigated than Option 2 (which is Option 1 plus a VTL) on account of the additional cost of the VTL outweighing the additional benefits expected.

This PADR assessment finds that VNI West, a new high capacity 500 kV double-circuit overhead transmission line to connect the Western Renewables Link (north of Ballarat) with Project EnergyConnect (at Dinawan) via new stations near Bendigo and near Kerang, has the greatest expected net market benefits of the two options assessed.

On a weighted basis, VNI West is expected to deliver approximately $687 million of net benefits over the assessment period, which is 19% greater estimated net benefits than if it were to be combined with a VTL.

VNI West is therefore the proposed preferred option identified as part of this PADR. It is also the preferred ISP candidate option in the 2022 ISP[147].

The analysis shows that the proposed preferred option is expected to efficiently provide supply reliability and put downward pressure on electricity prices by:

- Reducing the need for new dispatchable generation investment to meet demand going forward.
- Lowering aggregate generator fuel costs required to meet demand in the NEM going forward.
- Avoiding capital costs, by deferring or avoiding generation and storage investments that would otherwise be required, associated with enabling greater integration of renewables in the NEM.

VNI West is considered the option that maximises net market benefits and is therefore in the best interest of consumers, while supporting Australia's transition to net zero emissions and regional employment and economic growth.

The finding that VNI West maximises benefits to consumers is robust to a range of scenarios and sensitivity tests undertaken as part of this PADR, including higher network capital costs and lower VTL battery costs. Further, boundary testing indicates that network capital costs would need to increase by more than 45% for the investment to not provide a positive net market benefit under current assumptions.

VNI West comprises the following augmentations:

- A new 500 kV double-circuit line from north of Ballarat to near Bendigo to near Kerang to locality of Dinawan.
- Construction of the Dinawan to near Wagga Wagga line as a double-circuit 500 kV line rather than a double-circuit 330 kV line, and later upgrade from 330 kV to 500 kV operation (including new 500 kV bays and a transformer station near Wagga Wagga).

[147] AEMO, 2022 ISP, Appendix 5. Network investments, June 2022, p. 27.

- Establishing Dinawan 500 kV switchyard with two 500/330 kV 1,500 MVA transformers.
- New substations near Bendigo and near Kerang.
- Two 500/220 kV 1,000 MVA transformers at each of the new substations near Bendigo and near Kerang.
- 220 kV connections from the existing terminal station at Bendigo to new terminal station near Bendigo.
- 220 kV connections from the existing terminal station at Kerang to new terminal station near Kerang.
- Modular power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang and 220 kV lines between Dederang and Thomastown following certain contingencies.
- 500 kV line shunt reactors at both ends of the four following 500 kV circuits: (i) north of Ballarat – near Bendigo, (ii) near Bendigo – near Kerang, (iii) near Kerang – Dinawan and (iv) Dinawan – near Wagga Wagga.
- Up to +/- 400 MVAr dynamic reactive compensation at the new 220 kV terminal station near Kerang.

Modelling indicates that this option will result in additional transfer capacity of approximately 1,930 MW from Victoria to New South Wales and 1,800 MW from New South Wales to Victoria[148]. This option will increase the transmission limit at the following REZs facilitating additional generation development in the order of:

- 2,300-2,600 MW in the Murray River REZ (V2).
- 400-800 MW in the Western Victoria REZ (V3).

The project consists of approximately 400km of double-circuit 500 kV lines with an estimated capital cost of this option of approximately $3.256 billion: $1.605 billion in Victoria and $1.651 billion in New South Wales.

AVP and Transgrid expect VNI West to be progressed in two stages:

- Stage 1: carrying out early works as soon as possible.
- Stage 2: completing implementation of the project.

The early works need to progress as soon as possible to ensure the project can be delivered in time to meet the need identified in the *Step Change* scenario, and may include project initiation, community and stakeholder engagement, land-use planning, detailed engineering design, route development, biodiversity offset strategy, cost estimation, and strategic network investment. Early works will provide an opportunity to engage with and consult community and stakeholders on a range of matters and help with route selection. The works also will reduce cost uncertainties and inclusion of the feedback loop as an investment decision gateway will provide greater confidence to consumers that they will not be over- or under investing as part of VNI West.

Construction and inter-network testing under Stage 2 is expected to take five years once early works are complete, with commissioning depending on which scenario the NEM finds itself in (but ranging from 2030-31 to 2038-39).

[148] The 1,930 MW and 1,800 MW are considered underestimates of the increase in transfer capacity since the base case already assumes that the Dinawan to Wagga Wagga portion is upgrade to 500 kV (as outlined in section 2.6).

A1. Checklist of compliance clauses

This section sets out a compliance checklist which demonstrates the compliance of this PADR with the requirements of clause 5.16A.4(d) of the National Electricity Rules version 180 and Table 14 of the CBA Guidelines.

Table 12 Checklist of compliance clauses

NER clause	Summary of requirements	Relevant section(s) in PADR
5.16A.4(d)	The project assessment conclusions report must include:	-
	(1) include the matters required by the Cost Benefit Assessment Guidelines;	
	(2) adopt the identified need set out in the Integrated System Plan (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	Section 2
	(3) describe each credible option assessed	Section 5 and Appendix A2
	(4) include a quantification of the costs, including a breakdown of operating and capital expenditure for each credible option	Section 5
	(5) assess market benefits with and without each credible option and provide accompanying explanatory statements regarding the results	Section 8
	(6) if the RIT-T proponent has varied the ISP parameters, provide demonstrable reasons in accordance with 5.15A.3(b)(7)(iv)	Section 2.1
	(7) identify the proposed preferred option that the RIT-T proponent proposes to adopt	Section 10
	(8) for the proposed preferred option identified under subparagraph (7), the RIT-T proponent must provide: (i) details of the technical characteristics; and (ii) the estimated construction timetable and commissioning date.	Section 10
11.126.6	The PADR must address all submissions made by parties in response to the PSCR.	Section 4 and Appendix A4

Table 13 List of binding elements on RIT–T proponents in the CBA Guidelines

Binding elements	Provision	Classification	Relevant section(s) in PADR
1	RIT–T proponents are required to provide the AER with a compliance report when applying the RIT–T to an actionable ISP project, which must be submitted no later than 20 business days after the publication of the project assessment conclusions report	Requirement	Appendix A1
2	In its compliance reports, RIT–T proponents are required to identify where they: have complied with applicable requirements have had regard to applicable considerations (including the reasons for the weight they have attached to each consideration); and have resolved key issues raised by the AER through the issues register.	Requirement	Appendix A1
3	RIT–T proponents are required to identify breaches of the CBA guidelines, if any, in their compliance reports and provide an explanation for the breach.	Requirement	Appendix A1
4	If a compliance report contains confidential information, RIT–T proponents are required to provide another nonconfidential version of the report in a form suitable for publication.	Requirement	Compliance report does not contain confidential information
5	When a RIT–T proponent is considering whether to include new credible options that AEMO did not consider in the ISP, it must have regard to the guidance in section 4.3.1 of the CBA guidelines on what constitutes a credible option when	Consideration	Section 6 The PADR considers the

Binding elements	Provision	Classification	Relevant section(s) in PADR
	justifying its decision. When identifying new credible options, the RIT–T proponent must consider all options it could reasonably classify as credible options, taking into account factors that the RIT–T proponent reasonably considers it should take into account. In considering what it should take into account, the RIT–T proponent must have regard to the following: if the identified need in the ISP entails meeting a service standard, the degree of flexibility offered by that service standard; the advantages of constructing credible options with option value; and the benefits of constructing new credible options to meet the identified need in the ISP over broadly similar timeframes to the ISP candidate option and non-network options identified in the ISP.		option in the 2022 ISP and also a variant of this option that include a NNO component.
6	The base case is required to be where the RIT–T proponent does not implement a credible option to meet the identified need, but rather continues its business as usual activities, including for where reliability corrective action is driving the identified need.	Requirement	Section 8
7	'Demonstrable reasons' for departing from ISP parameters are required to be limited to where there has been a material change that AEMO would, but is yet to reflect in, a subsequent IASR, ISP or an ISP update. For example, this might include a material change in circumstances, such as where the AER has published updated VCR values that AEMO is yet to incorporate in the IASR. Where a material change is not a change in circumstances or facts (for example, a change in the RIT–T proponent's understanding or assessment of the facts, rather than a change in the facts themselves), the RIT–T proponent might choose to attain written confirmation of the change from AEMO.	Requirement	The PADR reflects parameters in the latest IASR and the 2022 ISP. As noted in Section 8.3, the RIT-T assessment undertook market modelling to develop modelled projects using the IASR inputs
8	If the modelling period is shorter than the life of the credible option, the RIT–T proponent is required to incorporate the operating and maintenance costs (if any) for the remaining years of the credible option into the terminal value.	Requirement	As noted in section 8.4, the terminal value included in the NPV assessment can be interpreted as a conservative estimate for benefits (net of operating costs) arising after the analysis period
9	When valuing the costs of compliance, there may be cases where a RIT–T proponent can lawfully pay a financial amount rather than undertake some other action for compliance. In such cases, the RIT–T proponent must consider whether the financial amount is smaller than the costs of undertaking some other action before determining whether it should treat the financial amount as part of that credible option's costs.	Consideration	N/A – options considered in the PADR do not involve cost of compliance payments of a financial amount in place of some other action for compliance.
10	For any RIT–T application where AEMO has not specified which scenario/s or weightings to apply, the RIT–T proponent must consider the AER's guidance on estimating probability-based weightings as set out in the previous RIT–T application guidelines that applied to all RIT–T projects.	Consideration	AEMO ISP scenario weightings adopted
11	RIT–T proponents must consider performing sensitivity testing by varying one or multiple inputs/assumptions. In considering whether or how to perform sensitivity testing, the RIT–T proponent must have regard to any relevant risks identified in stakeholder submissions, and whether sensitivity testing would build on the analysis already undertaken in the ISP and be proportionate and relevant to the RIT–T assessment.	Consideration	Section 7 and section 9.5
12	The RIT–T proponent must consider using the ISP modelling period (also known as the planning horizon) of 20+ years as the default when assessing credible options to meet identified needs arising out of the ISP. If the expected profile of the market benefits and costs of the ISP candidate option are longer than the modelling period used in the ISP, the RIT–T proponent must consider whether it might be valuable to adopt a longer modelling period, whilst also considering the need for alignment with the ISP.	Consideration	Section 8.4

Binding elements	Provision	Classification	Relevant section(s) in PADR
	For relatively incremental ISP candidate options, the RIT–T proponent must consider whether a shorter period would reduce the computational burden without compromising the quality of the CBA or undermining alignment with the ISP.		
13	Where the modelling period is shorter than the expected life of a credible option, the RIT–T proponent is required to include any relevant and material terminal values in its discounted cash flow analysis. The RIT–T proponent is required to explain and justify the assumptions underpinning its approach to calculating the terminal value, which represents the credible option's expected cost and benefits over the remaining years of its economic life.	Requirement	Section 8.4
14	For the purposes of clause 5.16A.5(b) of the NER, the relevant cost is the cost for the particular stage. However, AEMO also must have regard to the full cost of the project in providing its written confirmation, under clause 5.16A.5(b) of the NER, that the status of the actionable ISP project remains unchanged.	Consideration	Section 6.1, section 8.1 and appendix A3
15	The RIT–T proponent must consider describing in each RIT–T report how it has engaged with consumers, as well as other stakeholders; and sought to address any relevant concerns identified as a result of that engagement. The RIT–T proponent must consider undertaking early engagement with consumers, non-network businesses and other key stakeholders to the extent that doing so complements rather than duplicates or hinders AEMO's engagement work in developing the ISP. The RIT–T proponent also must have regard to how it can adopt best practice consumer engagement in line with our 'consumer engagement guideline for network service providers'.	Consideration	Section 4, section 5 and appendix A4.
16	The RIT–T proponent is required to provide transparent, user-friendly data to stakeholders, to the extent this protects commercially sensitive information and is not already provided by the ISP.	Requirement	Section 9 and modelling outcomes accompanying the PADR
17	In providing transparent, user-friendly data to stakeholders, the RIT–T proponent must have regard to how it can present information in line with stakeholder preferences.	Consideration	Section 9 and modelling outcomes accompanying the PADR
18	The Draft Report is required to include, if applicable: Demonstrable reasons for adopting different modelling techniques to what AEMO used in the ISP. An explanation as to why any non-network options proposed in response to new actionable ISP projects in the final ISP are not credible options.	Requirement	Section 8 describes estimating costs, benefits and modelling. Section 6.5 describes options considered but not progressed.
19	When publishing the Conclusions Report, RIT–T proponents are required to: Publish, in addition to a summary of submissions, any submissions received in response to the Draft Report, unless marked confidential. Date the Conclusions Report to inform potential disputing parties of the timeframes for lodging a dispute notice with the AER.	Requirement	N/A
20	If a RIT–T proponent receives any confidential submissions on its Draft Report, it must consider working with submitting parties to make a redacted or nonconfidential version public.	Consideration	N/A

A2. Refinement of the credible options

AVP and Transgrid have jointly undertaken a technical review of all credible options, as detailed in Section 5. This review included power system analysis and option design and was informed by a range of desktop due diligence studies to identify known land, planning and environmental constraints.

A2.1 Power system analysis

Detailed power system studies were conducted to test and refine the capability and scope of each credible option. An extensive range of steady state and dynamic PSS®E power system modelling was undertaken to determine and validate the thermal, voltage and transient stability limits associated with each credible option. These studies formed input to the market modelling and cost benefit analysis to determine the preferred option, as detailed in Section 9.

Section 5 describes the credible options assessed, including changes to the options since publication of the PSCR. The following key matters contributed to changes in the credible options:

Optimised option design:

- **Modular power flow control** – the VNI West PSCR detailed the need for power flow controllers to maximise the transfer capability of VNI West, particularly during periods of high transfer from New South Wales and Victoria. This function is required to divert power away from the existing VNI (east) corridor, which is prone to thermal constraints under certain conditions[149], and onto the new VNI (west) corridor, which has more power carrying capacity.
  - Since the PSCR, AVP and Transgrid have tested the technical feasibility of a range of power flow control solutions, as an alternate to traditional phase-shifting transformers or reactive compensation solutions, as part of the network option, that is, VNI West. The outcome of this analysis is that VNI West includes modular power flow technology as part of its scope.
  - AVP and Transgrid also investigated a sensitivity that removes the power flow controllers from VNI West, which shows that this would lower the overall net benefit from the investment. This confirms that the addition of the modular power flow controllers is net beneficial. This sensitivity is presented in Section 9.5.1.
- **Reactive plant** – steady-state and dynamic studies were performed to determine the optimum configuration of reactive equipment for each credible option. This analysis considered the requirements to manage system voltage during normal operating conditions as well as during periods of low demand and switching events such as line switching. Section 5 outlines the proposed reactive equipment required for VNI West, and changes since the PSCR.
- **Option transfer capacity and hosting capacity** – the existing VNI transfer capacity is dependent on a variety of factors including generation dispatch, weather, and demand profiles. Estimated additional VNI transfer capability and REZ hosting capacity figures are dependent on these factors in much the same way. A range of steady-state and dynamic studies were performed to test the capability of the credible options presented. The

[149] Analysis conducted for this PADR indicated that lines often prone to thermal overload during periods of high transfer from New South Wales to Victoria include Murray – Dederang 330 kV lines, South Morang – Thomastown 220 kV line, Eildon – Thomastown 220 kV line, Eildon – Mount Beauty 220 kV line and Dederang – South Morang 330 kV lines.

transfer capacity is robust across a range of assumptions. However, it should be noted that the REZ hosting capacity reported in this PADR was determined from studies testing favourable system conditions, that is, at times when interconnector flow on VNI West and other REZ generation export is low. Therefore, these figures provide an estimate of the maximum hosting capacity that may be achieved.

A2.2 Design and estimation

Desktop due diligence studies were undertaken to identify practical limitations and constraints within existing terminal stations. These included:

- Physical, land, planning and environmental constraints of the site.
- Space in the terminal station for the additional bays or new 500 kV switchyard.
- Availability of suitable easements for the 500 kV and 220 kV lines to exit the existing terminal stations at through population centres.
- Augmentations of existing equipment and lines to create space and capacity for interface to the new works and for line exits.

In some cases, study of the above limitations has resulted in the proposal of establishing 500 kV terminal stations outside of the existing terminal station boundaries.

Concept or reference designs were developed for the line and terminal stations with regard for the above due diligence. These designs were used to create a ground up estimate for the works.

A2.3 VNI West constraints and opportunity analysis data

The national and state-specific publically available data utilised during the desktop feasibility analysis (Table 14).

Table 14 Constraints and opportunity analysis data

#	Constraint / opportunity
National data	
1	Wetlands (incl. RAMSAR wetlands)
2	Waterway and waterbodies
3	Commonwealth - Defence
4	Commonwealth - other
5	Airports and licenced airstrips
6	Threatened ecological communities - Commonwealth (EPBC Act)
7	Threatened species and known habitats - Commonwealth (EPBC Act)
8	Urban centres
9	Indigenous - World heritage
10	Historical - World heritage
11	Native title
12	Historical Heritage - Commonwealth
13	First Peoples Heritage - Commonwealth
14	Terrain
15	Open Infrastructure Maps

#	Constraint / opportunity
New South Wales data	
16	Active mining tenements (including Large open-cut mining sites)
17	AHIMS sites
18	Areas of international environmental significance – World Heritage areas, declared wilderness areas
20	Bushfire risk
21	Conservation reserves (e.g national parks estate, areas subject to conservation planning policies, etc)
22	Crossings with existing transmission lines
23	Crown land
24	DIWA Wetlands
25	Flora and fauna sightings registered in BioNet
26	Historical Heritage - State
27	Intensive agricultural and horticultural uses
28	Known Aboriginal places
29	Land reserved under the National Parks and Wildlife Act 1974
30	Local non-Aboriginal heritage conservation items and conservation areas
31	Major infrastructure crossings (waterway / railway)
32	Major Projects
33	Major utilities
34	Mine subsidence zones
35	Native vegetation
36	Plant community types
37	Public land - National/Marine Parks, State Parks
38	Significant landscapes, Environmentally significant land
39	Soil and contamination
40	State Forests
41	Threatened ecological communities - State (various)
42	Threatened species and known habitats - State
43	Townships and residential areas
44	Unlicensed airstrips
Victoria data	
45	Airport infrastructure
46	Bushfire risk
47	Townships and residential areas
48	Native vegetation
49	Threatened ecological communities
50	Threatened species and known habitats - State
51	Threatened population and known habitat - State
52	Public land - National/Marine Parks
53	Public land - State Parks
54	Current Extractive Industry Tenements
55	Significant landscapes include airport environs overlay
56	Environmentally significant land
57	Historical Heritage - State
58	Wetland Inventory
59	Geology

#	Constraint / opportunity
60	Floodways
61	Precinct Structure Plans
62	Zoning and overlays
63	Transport infrastructure
64	Gas and Fuel Pipelines
65	Major projects
66	Utilities
67	Landfills
68	Land Use
69	Parks and Conservation Reserves
70	Registered Aboriginal Parties (RAP)
71	Cultural Heritage Sensitivity
72	Known cultural heritage places

A3. Cost estimating methodology

Significant work has been undertaken since the PSCR to develop more accurate cost estimates for the options, including in light of the various social impacts and network topology considerations raised in submissions. The cost estimates presented in this PADR have been undertaken on a jurisdictional basis with AVP responsible for the estimates of the part of the options located in Victoria and Transgrid responsible for the estimates of the part of the options located in New South Wales.

This appendix provides additional detail on the cost estimating methodologies applied by AVP and Transgrid for each of the key categories of cost.

A3.1 Cost estimating methodology for the Victorian components

The cost estimates were prepared on a desktop basis, utilising historical data available to AVP and where applicable, updated with current market costs.

The VNI West cost estimates used in this PADR differ from that presented in the 2022 ISP by approximately $314 million. As outlined in Section 5.1.2, this additional contingency cost is in anticipation of some level of route diversion, tower redesign, or screening beyond that included in the cost estimate presented in 2022 ISP.

As discussed in Section 8.4 the cost estimates are higher on a present value basis than those in the ISP due to the profiling of the early works and construction activities.

Early works

AVP has estimated the cost of conducting early works as soon as possible to ensure the project can be delivered by July 2031 (the target commissioning date in the most likely ISP scenario). As defined in the ISP, early works may include:

- Project initiation – scope, team mobilisation, service procurement.
- Stakeholder engagement – with local communities, landholders and other stakeholders.
- Land-use planning – identify and obtain all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection and easement acquisition.
- Detailed engineering design – transmission line, structure and substation design, detailed engineering design and planning.
- Cost estimation – finalisation, including quotes for primary and secondary plant.

Substations

Terminal station estimates were bottom up estimates utilising typical terminal station layouts and indicative concept designs created for the various terminal stations. Unit prices used for this bottom up estimate were based on historical data available to AVP and where applicable, updated with current market costs. These estimates include:

- Design and project management.

- Plant and equipment.
- Installation.
- Civils.
- Commissioning.

Specifically, allowance has been made to establish:

- A new 500/220 kV substation near Kerang, including two 1,000 MVA transformers and four 100 MVAr 500 kV line shunt reactors.
- A new 500/220 kV substation near Bendigo, including two 1,000 MVA transformers and four 100 MVAr 500 kV line shunt reactors.

At the new substation north of Ballarat, planned to be built as part of the Western Renewables Link, allowance has been made to install two new 500 kV Line exits with a total of two 100 MVAr 500 kV line shunt reactors.

Line works

Line cost estimations are highly dependent on site-specific matters including terrain, topology, geotechnical and soil conditions. Typical structure types, span lengths and construction methodologies have all assumed in order to develop reasonable cost estimates. Line lengths have further been refined from the initial PSCR estimates utilising a preliminary desktop approach of identifying and avoiding known technical, land, planning and environmental constraints.

Like the estimate for the terminal stations, the line estimate was a bottom up estimate and includes:

- Materials.
- Construction work.
- Preliminaries and overheads.

The cost estimate for the new transmission line was based on a double-circuit tower line, with four conductors per phase per circuit. Allowance has also been made for optical ground wire (OPGW) and line surge arrestors.

Battery costs (for the VTL option)

The VTL option was estimated in two parts:

- The first part consists of the battery system and is based on inputs to AEMO’s 2021 IASR.
- The second part consists of the terminal station works to interface the battery system to the substations. The estimate for this work followed the same approach as the substation estimates (outlined above). These estimates were bottom up estimates utilising typical terminal station layouts and indicative concept designs created for the various terminal stations. Unit prices used for this bottom up estimate were based on historical data available to AVP and where applicable, updated with current market costs and site conditions and include the items listed for the substation estimates (outlined above).

Power flow controllers

The modular power flow controllers were estimated in two parts:

- The first part consists of the actual modular power flow controllers and was estimated based on market costs for the design, supply and installation of the modular power flow controllers.
- The second part consists of the terminal station works to interface the modular power flow controllers to the substations. The estimate for this work followed the same approach as the substation estimates for the substation estimates (outlined above). These estimates were bottom up estimates utilising typical terminal station layouts and indicative concept designs created for the various terminal stations. Unit prices used for this bottom up estimate were based on historical data available to AVP and, where applicable, updated with current market costs and site conditions and include the items listed for the substation estimates (outlined above).

Property/land access/easements

Easement compensation

An assessment of the likely easement compensation costs has been undertaken with consideration to Section 41 of the *Land Acquisition and Compensation Act 1986* and the likely zoning, locality and parcel size. An estimate of ongoing land tax costs for easements located in Victoria has been included within this assessment.

Land acquisition

An estimate of land acquisition costs for new terminal stations near Kerang and near Bendigo have been developed based on recent sales evidence for suitable sites at these locations. Rates for these locations are dependent on the zoning, locality, usability and parcel size.

An estimate of ongoing land tax costs for the terminal sites has been included within this assessment.

No individual land or easement valuations can be completed at this stage of the project, as no route is determined.

Biodiversity offset costs

The biodiversity offset calculations required the determination of the extent of native vegetation that could potentially be impacted by the proposed credible option. This was achieved through running an indicative 'scenario test native vegetation removal' report using the Victorian Department of Environment, Land, Water and Planning's Environmental Systems Modelling Platform (EnSym).

The resultant offset requirements from the scenario test included:

- General Habitat Unit (GHU) offset requirements, measured as general habitat units for overall biodiversity impacts to native vegetation.
- Large Tree losses, estimated at five per hectare within vegetation classes comprising a tree canopy element.
- Species Habitat Unit (SHU) offset requirements, measured as species habitat units for impacts to rare or threatened species.

Significant impacts on Environmental Protection and Biodiversity Conservation (EPBC) listed vegetation communities and/or threatened flora or fauna that represent matters of national environmental significance are likely to trigger biodiversity offset requirements. Species listed under the *Environmental Protection and Biodiversity Conservation Act* have been identified using the EnSym scenario results, which document the estimated proportion of modelled habitat impacted and potential impacts and estimated offset requirements.

A3.2 Cost estimating methodology for the New South Wales components

The cost estimates were based on a desktop identification and analysis of the credible options with associated line work and substations.

The unit prices used for these estimates were based on historical data available to Transgrid and, where applicable, updated with current market costs.

A further desktop analysis of environmental, social and community, engineering and property constraint criteria was also used to inform the corresponding cost elements.

Transgrid estimated the costs of projects and programs using its estimating tool 'MTWO'[150]. The MTWO cost estimating database reflects actual outturn costs built up over more than 10 years from:

- Period order agreement rates and market pricing for plant and materials.
- Labour quantities from recently completed project.
- Construction tender and contract rates from recent projects.

The MTWO estimating database is reviewed annually to reflect the latest outturn costs and confirm that estimates are within their stated accuracy range and represent the most likely expected cost of delivery (P50 costs). As part of the annual review, Transgrid benchmarks the outcomes against independent estimates provided by various engineering consultancies.

All cost estimates in New South Wales have been developed at a high level based around the scope of work for the relevant option.

Early works

Transgrid has estimated the cost of conducting early works to ensure the project can be delivered by July 2031 (the target commissioning date in the most likely 2022 ISP scenario). As described in the 2022 ISP, early works may include:

- Project initiation – scope, team mobilisation, service procurement.
- Stakeholder engagement – with local communities, landholders and other stakeholders.
- Land-use planning – identify and obtain all primary planning and environmental approvals, route identification, field surveys, geotechnical investigations, substation site selection and easement acquisition.
- Detailed engineering design – transmission line, structure and substation design, detailed engineering design and planning.
- Cost estimation – finalisation, including quotes for primary and secondary plant.
- Strategic network investment – an uplift to the delivered capacity of Project EnergyConnect between Dinawan and Wagga Wagga, as outlined below.

[150] MTWO is a virtual-to-physical 5D BIM enterprise solution, designed to bring together all stakeholders and workflows on a single, cohesive platform. Built upon a bespoke vertical cloud infrastructure supplied by Microsoft Azure, MTWO allows users to integrate and digitalise all project delivery processes in a complete end-to-end solution. More than 100 enterprise-wide modules are built into MTWO, with everything from 5D BIM virtualisation to scheduling, procurement, bidding and tendering on offer. RIB's iTWO cx project management software is also available as part of the MTWO solution.

Project EnergyConnect enhanced works (incremental line build cost)

Following the Federal Government underwriting[151], Transgrid committed to construct approximately 160 km of Project EnergyConnect to a 500 kV specification instead of 330 kV. The relevant transmission line section runs between the proposed Dinawan Substation (south of Coleambally) and Wagga Wagga. The $181.5 million underwriting will see a 500 kV double-circuit tower line constructed as part of the early works for VNI West.

The incremental cost permits the environmental assessment for, and the design and construction of, larger towers, additional conductors and associated line accessories.

Substations

Substation estimates were bottom up estimates utilising typical substation layouts and indicative concept designs created for the various substations. Unit prices used for this bottom up estimate were based on historical data available in Transgrid's MTWO estimating database. These estimates include:

- Design and project management.
- Plant and equipment.
- Installation.
- Civils.
- Commissioning.

Specifically, at Dinawan, a new 500 kV substation will be established including 2 x 1,500 MVA transformers and 4 x 150 MVAr 500 kV line shunt reactors. At the proposed Gugaa substation, allowance has been made to install 1 x 1,500 MVA transformer and 2 x 150 MVAr 500kV line shunt reactors.

Line works

Line cost estimations are highly dependent on site-specific matters including terrain, topology, geotechnical and soil conditions. Typical structure types, span lengths and construction methodologies were all assumed to develop appropriate cost estimates. Line lengths were further refined from initial PSCR estimates utilising a preliminary desktop approach of identifying and avoiding known technical, land, planning and environmental constraints.

The line estimate was a bottom up estimate and includes:

- Materials.
- Construction work.
- Preliminaries and overheads.

The cost estimate for the new transmission line was based upon a double-circuit tower line, with four conductors per phase per circuit. Allowance has also been made for optical ground wire (OPGW) and line surge arrestors.

Battery costs (for the VTL option)

The VTL option was estimated in two parts:

[151] See https://www.minister.industry.gov.au/ministers/taylor/media-releases/government-supporting-delivery-critical-transmission-infrastructure-southwest-nsw.

- The first part consists of the battery system and is based on inputs to AEMO's 2021 IASR.
- The second part consists of the terminal station works to interface the battery system to the substations. The estimate for this work followed the same approach as the substation estimates (outlined above). These estimates were bottom up estimates utilising typical terminal station layouts and indicative concept designs created for the various terminal stations. Unit prices used for this bottom up estimate were based on historical data available to Transgrid and where applicable, updated with current market costs and site conditions and include the items listed for the substation estimates (outlined above).

Power flow controllers

Refer to the Victorian section above on how power flow controllers have been estimated.

Property/land access/easements

An estimate for land acquisition and easements cost was developed from recent similar projects in the region. A 70 metre width allowance was made for 500 kV transmission line easements. Property costs for the proposed Dinawan and Gugaa substations are covered by other ISP projects and no allowance has been made as part of the network option for this project.

No individual property valuations can be completed at this stage of the project, as no route is determined.

Biodiversity offset costs

A high level and indicative estimate of biodiversity offsets costs was prepared for the network option to approximate the potential scale of the biodiversity offset cost for the project. The approach taken to inform the indicative biodiversity cost estimate included identifying a nominal credit value and a nominal threatened Ecological Communities (TECs) clearance area for threatened ecological communities.

The weighted average credit prices were taken from the New South Wales Department of Planning and Environment Spot Price Index. Furthermore the Biodiversity Assessment Method Calculator (BAM-C) tool was used to identify the number of Ecosystem Credits and Species Credits that would be required for a nominal clearance area (access tracks and easements).

A4. Summary of consultation on the PSCR

This appendix provides a summary of all non-confidential points raised by stakeholders during the PSCR consultation process. The points raised are grouped by topic and a response is provided to every point raised. All section references are to this PADR, unless otherwise stated.

Table 15 Summary of points raised in consultation on the PSCR

<table>
<tr><th>Summary of comment(s)</th><th>Submitter(s)</th><th>Response</th></tr>
<tr><td colspan="3">Scope of the options included in the assessment</td></tr>
<tr><td colspan="3">Refinements to the network options considered</td></tr>
<tr><td>A variation of the ISP VNI 6 route that would connect into the 500 kV network at a new terminal station site north of Melbourne should be investigated. The proposed route runs from Wagga Wagga – Shepparton – South Morang.
This option could be delivered more quickly due to fewer outage constraints and availability of existing land and easements that form part of AusNet Services strategic land holdings.</td><td>AusNet Services, p 2.</td><td>The VNI 6 option put forward in the PSCR and included in the 2020 ISP was ruled out in the 2022 ISP. See Section 4.2.</td></tr>
<tr><td>An extension of VNI 5A to consider versions going to Maragle and being at 500 kV should be considered.</td><td>EnergyAustralia, p 1.</td><td rowspan="2">VNI 5A was considered but not progressed in the 2020 ISP on the basis that the absence of REZ hosting capacity and interconnector diversity made it an uneconomic investment.[A] As outlined in Section 6.4, AVP and Transgrid therefore have not considered it further in this PADR.</td></tr>
<tr><td>VNI 5A should be assessed for a 500 kV sub-option with a 500 kV link from Hume substation to Maragle.</td><td>Major Energy Users (MEU), p 10.</td></tr>
<tr><td>REZ extensions from Dederang to Glenrowan for VNI 5A, and from Buronga to Red Cliffs for VNI 5A and VNI 6 should be considered.</td><td>EnergyAustralia, p 2.</td><td>VNI 5A was considered but not progressed in the 2020 ISP on the basis that the absence of REZ hosting capacity and interconnector diversity made it an uneconomic investment.[A] As outlined in Section 6.4, AVP and Transgrid therefore have not considered it further in this PADR.
The VNI 6 option put forward in the PSCR and 2020 ISP was ruled out in the Draft 2022 ISP, as outlined in Section 6.4. It has therefore no longer been considered in this RIT-T.</td></tr>
<tr><td>Propose that modular power flow control (PFC) equipment should be considered as part of the options analysis.</td><td>Smart Wires, p 3.</td><td>AVP and Transgrid has tested the technical feasibility of a range of power flow control solutions and included power flow technology as part of the VNI West scope. See Section 4.2.</td></tr>
</table>

Summary of comment(s)	Submitter(s)	Response
The Victorian transmission system currently has multiple issues that require resolution, including system strength and stability issues, the need for additional network capacity to enable new generation connections and the need for development of future REZ. Selection of the most efficient solution to the primary need of supply reliability should be made whilst complementary solutions to other issues are considered in parallel through processes focussed on these separate issues.	AusNet Services p 1.	In line with the actionable ISP framework, AVP and Transgrid has focused on the identied as outlined in this PADR. See Section 4.2.
Staging the network options		
Clarification sought as to whether the costs of options 6, 7 and 8 allow for single-circuit or double-circuit towers and request that staged development of single-circuit options to allow staged line implementation is considered to reduce overall costs to consumers.	EnergyAustralia, p 1.	Developing portions of the scope sequentially or changing the scope as suggested in submissions is not considered able to meet the identified need as set out in the 2022 ISP and this PADR. See Section 4.2.
Consider staged options that achieve the near-term requirements for increased transmission network transfer between the Victorian and New South Wales regions and incorporates options to add additional capability at a later date, if required. Recommend that double-circuit towers are initially strung on one-side only, due to lower initial costs to consumers leaving options for future augmentation.	ERM Power pp 2, 4.	
Strong support for staging investment as there is significant uncertainty as to what market development changes might occur in the future.	MEU pp 12-13.	
It would be more practicable to implement a staged approach with portions of the scope being developed sequentially. Recommend that the Ballarat to Bendigo to Kerang branch is developed first.	Pacific Hydro, pp 1-2.	
Staged development would reduce the time for completion and could provide additional benefits.	Snowy Hydro, p 7.	
Better scoping and sequencing of VNI 7, such as early thermal and structural capacity upgrade to the Kerang to Bendigo 220kv line, could unlock substantial additional solar power generation in the very short term.	Donald McGauchie p 3.	
Support for an accelerated delivery of the preferred option		
Supports the accelerated timeline for VNI West and notes that the draft 2020 ISP recommends delivery by 2026-27, which is more than 10 years earlier than expected in the 2018 ISP. Project delivery earlier than 2026-27 could be economic, however delivery earlier than this date may not be practicable and so the evaluation criteria for various options should consider delivery timelines and risk factors that may impact delivery for each option.	AusNet Services p 3.	The 2022 ISP called for VNI West to be progressed as urgently as possible. With support, it may be possible to construct the project earlier. The benefits of doing so have not been assessed in the ISP or this PADR given that any further acceleration of delivery would require additional support outside the current regulatory and planning processes.See Section 4.3.
Delayed or late delivery of critical transmission, energy storage and additional flexible capacity represents a significant risk for energy consumers. Hydro Tasmania supports the timely application of the RIT-T guided by the ISP roadmap in clearing the pathway to advance critical infrastructure and transition the NEM to a cleaner fuel mix.	Hydro Tasmania p 3.	

Summary of comment(s)	Submitter(s)	Response
Project completion timeframes outlined in the PSCR are too long and that investment in this critical infrastructure must be brought forward as a matter of urgency.	Murray River Group of Councils (MRGC), p 5.	
It is clear from the challenges faced by the present electricity transmission infrastructure, from frequent islanding events to tower structural collapses, that reinforcing and augmenting the power system to enable larger interstate flow and wider renewable generation deployment requires urgent attention.	Pacific Hydro, p 1.	
The PADR should include discussion on the choice of optimal timing for the VNI West.	Origin, pp 1-2.	
The VNI West commissioning date should be no later than 2025, which aligns with Victoria's renewable energy targets (VRET) target date. This date will provide system resilience to cater for unplanned early exit of coal plant, by allowing Snowy 2.0 to firm VRET output and capture excess or low value generation for discharge during times of energy scarcity, and will facilitate orderly transition to the future renewables dominated power system.	Snowy Hydro, p 2.	
Consideration of non-network options		
Propose commissioning BESS at two substations to act as a VTL (one in Victoria and one in New South Wales) to relieve the limitations on the existing interconnector (VNI): 250MW/125MWh system at South Morang; and 250MW/125MWh system at Wagga Wagga.	Fluence pp 2, 10.	A non-network VTL has been included as a component of a second credible option in the PADR assessment, combined with VNI West. See Section 6.3.
Social impacts and network topology considerations		
Assessment of the feasibility of obtaining access to land and easements required for each option should be considered, along with requirements for approvals, consents and impact assessment.	AusNet Services p 3.	Transgrid and AVP agree that consideration of social impacts and land use should be taken into account in this PADR. See Section 4.10.
VNI 6 is slated to run through high value agricultural farmland including a high concentration of irrigation infrastructure investment and related agricultural production. This region has already demonstrated serious local concerns regarding planning approval, which would likely impact timing and cost of construction as well as limiting development of new renewable generation in the area. VNI 7 runs through lower value agricultural land well suited to solar power generation, with a demonstrated track record of major project planning approval.	Donald McGauchie p 3	The VNI 6 option was ruled out in the 2022 ISP is therefore no longer being considered in this RIT-T. See Section 4.10.
VNI-6 traverses high quality soils and significant irrigation infrastructure.	MRGC, p 4.	
The north-west of Victoria has suitable topography for such infrastructure and the social license of the region would provide pathways for support.	MRIC, p 12.	
We note that the challenges associated with the Shepparton corridor and its high agricultural value also include irrigation infrastructure as a major technical and community constraint.	Pacific Hydro, p 3.	

Summary of comment(s)	Submitter(s)	Response
North-western Victoria is characterised by flat wide open country whereas north-eastern Victoria's landscape has significantly greater coverages of steep ranges and the foothills of the Great Dividing Range. This may mean that route selection will likely be more constrained and environmental impacts of developing the Shepparton Link are more significant. Similarly, new generation is less likely to occur in the environmentally sensitive landscapes of the Great Dividing Range and its foothills.		
Not considering the project holistically risks delivering outcomes which are not aligned with the aspirations of local communities – leading to low social acceptance and consequently unnecessary delays, costs, community division and tensions. The utilization of multi-criteria decision methodology at early project stages may allow potential problems to be identified, while minimizing negative outcomes in later project stages.	Hepburn Shire Council, p 2.	AVP and Transgrid recognise the importance of stakeholder engagement and will continue to work closely with consumer representatives to understand consumer concerns and articulate consumer benefits clearly as this project progresses. While the RIT-T does not allow for multi-criteria decision making when there is a clearly preferred option, subsequent stages of the wider investment process (of which the RIT-T forms only one part) use multi-criteria decision making, for example, detailed option development and route selection.
Selection of a preferred route based solely on technical evaluation of power flows and desk top assessments will not provide a complete view of relevant factors and is likely to lead to selection of an option that is at significant risk of not being able to be delivered within estimated time and cost parameters.	AusNet Services p 3.	The RIT-T does not address line route specifics and, instead, these are scoped by the TNSP(s) for the ultimately preferred option and assessed within the Environmental Impact Statement (EIS) process following the RIT-T. AVP and Transgrid have put significant effort into estimating the cost and delivery timeframes for the options assessed. At this stage, they reflect our best estimates.
Interaction with other major transmission investments		
There has been no formal commitment for many other major transmission projects to proceed (ie formal decisions by the firms involved to commit the funds). Sensitivities should explore cases where options do not proceed, or proceed in a different form to that assumed in the VNI West PSCR.	MEU p 5.	In line with the AER's Cost Benefit Analysis Guidelines, the modelling in this PADR reflects the actionable ISP projects and major transmission projects in the ISP optimal development path, and AVP and Transgrid note that inclusion of these projects in all PADR analysis is a requirement of the CBA Guidelines, unless a 'demonstrable reason' can be provided for not including them. See Section 4.5
Other major transmission projects may affect the optimal timing for the identified need and underestimate the potential costs of the options, in turn affecting the case for deferring network investment through non-network options. Recommend that costings for VNI West options are provided with and without the anticipated completion of Minor VNI and HumeLink projects while these are still undergoing regulatory review.	PIAC, pp 1-2.	
Should consider a range of timings for other interconnector projects when determining the net market benefit provided by VNI West and, in particular, those interconnector projects for which RIT-Ts are not complete (Marinus Link and the medium or large Queensland-New South Wales Interconnector (QNI) upgrades).	TasNetworks p 2.	
The other RIT-Ts currently underway should be completed prior to their inclusion in the VNI West PADR modelling. It is not appropriate to include proposed benefits of incomplete RIT-Ts in the PADR modelling prior to their completion. We believe the inclusion of uncommitted benefits from	ERM Power pp 3-4.	

Summary of comment(s)	Submitter(s)	Response
incomplete RIT-Ts in the benefit assessment of the VNI West project results in overstating the market benefit delivered solely by the VNI West project.		
The MEU is aware that other elements of the interconnection proposed under the ISP are at various stages of approval. The MEU considers that all of these projects are very dependent on each other to deliver benefits to consumers as does the proposed VNI West project. In particular it is unclear to the MEU that HumeLink will a deliver net benefit absent VNI West or that VNI West can deliver a net benefit absent HumeLink. As all of the eight projects have a degree of co-dependency, the MEU considers that all of the projects should have their benefits assessed as an entire project so that benefits claimed by one project are not also claimed by another project.	MEU pp 4-5.	
Clarification on which major projects are included and excluded from the modelling, with an explanation of why these choices have been made. It is not clear whether the inclusion of other projects (and uncertainty around construction dates) in the cost-benefit analysis means that individual RIT-Ts over-estimate the benefits of a project, by double counting gains from other projects. Providing sensitivities that exclude other transmission projects under way help understand these interactions.	Origin, p 2.	
We would like to see more co-ordinated evaluation of the various projects to increase New South Wales – Victorian interconnection to ensure benefit streams are not being double counted in each separate RIT-T process and the impact of recent New South Wales Government announcements on REZs will be taken into account.	EUAA p 1.	The ISP is underpinned by a NEM-wide cost-benefit assessment that identifies the optimal development path across the NEM. The role of this RIT-T is to identify the most efficient way to meet the need by extending and refining the ISP analysis, rather than duplicating the ISP analysis.
We encourage AEMO to consider the role of offshore wind (and specifically the Star of the South) as a credible option which impacts on the timing of the need for VNI West. We believe there is merit in considering a state of the world where the Star of the South is built and fully commissioned by early 2027 as Australia's first offshore wind farm.	Star of the South, p 1.	As at the date of this report, the Star of the South development is not considered either 'committed' or 'anticipated' under the RIT-T. The RIT-T framework allows market modelling to consider potential future generation, known as 'modelled generation', in addition to existing, committed and anticipated generators. This modelled generation is optimally located and sized by the model on the basis of least cost utilisation of REZ hosting capacity across the NEM. In line with the 2021 IASR, the PADR modelling has allowed for up to 10,000 MW of offshore generation in Gippsland, which has significant offshore wind development interest. On the basis of costs, the wholesale market modelling in this PADR is finding that no offshore wind capacity is built in the *Progressive Change* and *Hydrogen Superpower* scenarios. However, in the case of the *Step Change* scenario base case, 733 MW of offshore wind capacity in the Gippsland region has been built by 2047-48 with build starting in the prior year. There is no offshore wind build in the 'step change' scenario under Option 1 and Option 2. As noted in Section 7.1 , the 2022 ISP analysis found that the expected benefits of VNI West increased by approximately $67 million with the inclusion

Summary of comment(s)	Submitter(s)	Response
		of the offshore wind targets specified in the Victorian Government's Directions Paper.
Accuracy of the cost estimates presented		
There is a lack of supporting evidence behind the capex numbers used in the modelling and the lack of engagement on those estimates. Estimates are indicated as +/- 50% with regards to accuracy. While this is understandable at a PSCR stage, we look forward to AEMO providing a much more robust estimate of the capex in the PADR and PACR.	EUAA p 3.	Significant work has been undertaken since the PSCR to develop more accurate cost estimates for the options included in this PADR assessment. The costs have also been broken down in to key cost categories provide increased transparency of the cost build up. See Section 4.6
The PADR capex estimate should be a +/- 20% estimate and involve the application of a degree of AACE methodology to provide stakeholders confidence around that the PADR conclusions support proceeding to the PACR.	EUAA pp 3-4.	
Considering the importance of estimating costs with reasonable accuracy to ensure future consumer costs are transparent and minimised, we recommend that a maximum +/- 20% accuracy band apply to base cost estimates used in the PADR assessment.	ERM Power p 3.	
There is no detail as to how the PSCR costs were developed other than a statement that the costs have an accuracy of +/- 50%. The MEU points to the recent review of the Project EnergyConnect project reviewed by the AER under the RIT-T process where the AER raises concerns about the accuracy of the expected costs and the risk to the project should the costs be higher than forecast.	MEU p 7.	
Propose the modelling is refined by: • making the PACR estimate +/- 5% and that: • it is the cap of any subsequent contingent project application to the AER; and • the PACR contain letters from AEMO and Transgrid undertaking that they are prepared to build their portion of the preferred option at no higher cost than the respective agreed caps; and • AEMO undertaking detailed stakeholder consultation on the methodology to be used to develop these estimates as part of the PADR – similar in style and content to that which AEMO has undertaken for other major ISP assumptions and methodology.	EUAA p 3.	
VNI 5A is similarly costed to VNI 6 in the PSCR, despite a significant difference in line length between the two options and operating voltage. We are also concerned that the costs indicated in this PSCR are significantly higher than the costs indicated in the 2017 Victorian TAPR (where a new single-circuit 330 kV between Murray, Dederang and South Morang was indicated as $420 million). Request that AEMO clarify the transfer capacity of VNI 5A. We have observed that a number of 330 kV circuits operate with a rated capacity close to 1,400 MW.	ERM Power p 5.	As outlined in Section 6.5, VNI 5A has not been progressed as part of this PADR.
The PSCR only considers that the new 330 kV line under VNI 5A would provide a nominal rating southwards flow of only 1000 MW. The MEU understands that most new 330 kV transmission lines have a rated capacity of 1,400 MW and so there is a need to explain why VNI 5A has been effectively derated to a low transfer capability.	MEU p 11.	

Summary of comment(s)	Submitter(s)	Response
Intrigued why the proposed cost for VNI 5A is as high as $815 million considering it is an upgrade of the existing network. In comparison, the entirely new higher voltage and longer powerline from a new terminal station north of Ballarat to Wagga requires only 50% more capital.		
Interaction with the Victorian Big Battery		
Since AEMO published the PSCR, the Victorian Government and AEMO have sought expressions of interest for the provision of a SIPS service capable of enabling an additional import capacity of up to 250 MW on the existing VNI. AEMO to provide clarity of how the identified need for this RIT-T is impacted by the proposed provision of a SIPS for Victoria. AEMO should also reflect this in its analysis of credible options and its consideration of non-network options.	PIAC, pp 1-2.	The Victorian Big Battery has been reflected in the wholesale market modelling undertaken for this PADR, including its effect (increase) on transfer limits between New South Wales and Victoria while it provides the SIPS service for the five contracted months a year (until 31 March 2032). See Section 4.7.
Given that the 2020 SIPS project is aimed at increasing transfer capacity between New South Wales and Victoria at times of peak demand, it would be useful to understand its impact on the VNI West identified need and net benefits.	Origin, p 2.	
The SIPS delivers similar benefits that will impact the value of the benefits included in the PSCR for VNI West.	MEU p 5.	
Comments on costs and benefits included in the assessment		
Considering the proportional change away from dispatchable to non-dispatchable capacity because of project, this may lead to an increase in the need for FCAS and NCAS.	EnergyAustralia p 2.	While modelling all aspects of costs and benefits is complex, AVP and Transgrid consider all material costs and benefits have been captured. See Section 4.8.
AEMO must provide a cost-benefit analysis on the improvement in reliability that will occur by having VNI West separated from the existing VNI easement and what this improved reliability will do to the reliability seen by consumers.	MEU p 9.	
All necessary augmentation of both New South Wales and Victorian networks for increased interregional transfer should be included in the costs for all options, eg, some options may require intra-regional upgrades in order to alleviate congestion caused by the new transfer capacity or to unlock the full benefits of augmentation.	Origin, p 3.	
Comments on the Identified need		
General agreement with the identified need of maintaining supply reliability and capacity for future demand		
Agree that there is an identified need to increase transfer capacity. There are high quality renewable resources available both sides of the border that should be developed and shared between both States and to the wider NEM as coal fired stations close.	EUAA p 2.	Noted. VNI West would increase hosting capacity in Victoria and New South Wales.
The Victorian transmission network requires significant and urgent upgrading to ensure reliable supply into the future and to enable the State to meet its ambitious 50% renewable energy target by 2030.	Gannawarra Shire Council p 2.	Noted. VNI West would increase reliable supply.
Increasing the capacity of the VNI southward flow is needed to better provide for the long term interests of consumers.	MEU pp 3, 7.	Noted. VNI West would increase both northward and southward flow capacity between Victoria and New South Wales.

<table>
<tr><th>Summary of comment(s)</th><th>Submitter(s)</th><th>Response</th></tr>
<tr><td colspan="3">Clarification about values for amount of increased transfer capacity required to meet the identified need</td></tr>
<tr><td>It is not clear what amount of increased interconnection capacity is required to satisfy the identified need, nor why the particular options to be examined in detail in the PADR were chosen.</td><td>EUAA p 2.</td><td rowspan="3">This RIT-T is being undertaken in accordance with the actionable ISP framework[152]. Under this framework, the ISP establishes the identified need and considers a range of options for each network need as part of developing the optimal development path across the NEM. AVP and Transgrid consider that the increase in transfer capability required from credible options needs to be substantive to meet all three elements of the identified need in the 2022 ISP. See Section 4.9.</td></tr>
<tr><td>An assessment as to the level of transfer capability that is being sought by the augmentation is absent from the identified need. Without identifying what the transfer capacities is needed by consumers (in terms of MW flow north and south), the MEU is at a loss to see how AEMO identify which option best meets the needs of consumers and so determine what baseline value the proposed augmentation is to provide.</td><td>MEU pp 8-9</td></tr>
<tr><td>The ‘identified need’ description could be improved by providing a clear description of the relativity and quantum of benefits provided by each driver. AusNet Services understands that most of the project benefits relate to maintaining Victorian supply reliability and if this is the case then the efficient solutions should be considered in this context.</td><td>AusNet Services p 1.</td></tr>
<tr><td colspan="3">Other comments</td></tr>
<tr><td colspan="3">Interaction with Renewable Energy Zones</td></tr>
<tr><td>The PADR will need to closely examine how the announcement by the New South Wales Government supporting the development of REZs in New South Wales will impact on this RIT-T analysis.</td><td>EUAA, p 2.</td><td>The New South Wales Roadmap has been modelled consistently with the assumptions used in the 2022 ISP (i.e., as outlined in the 2021 IASR).</td></tr>
<tr><td>The PADR should include an explanation on the role of the two REZ expansions and how they fit into the ISP’s optimal development path.</td><td>Origin, p 3.</td><td>The indicative impact on REZ transmission limit is included in Table 3, Section 6.1.</td></tr>
<tr><td>Supports VNI 6 because it opens up a significant new renewable energy development area to future network connection opportunities which were unavailable until now.</td><td>Neoen, p 2.</td><td>The VNI 6 option put forward in the PSCR and 2020 ISP was ruled out in the Draft 2022 ISP, as outlined in Section 6.5. It has therefore no longer been considered in this RIT-T.
Moreover, both network options assessed in this PADR contribute to supporting REZ development.</td></tr>
<tr><td>Route selection for VNI West must not be influenced in seeking to minimise the costs of potential future REZ connection and we do not support the provision of REZ connection assets via regulated transmission network investment paid for by consumers.</td><td>ERM Power p 2.</td><td rowspan="2">The RIT-T does not address line route specifics and, instead, these are scoped by the TNSP(s) for the ultimately preferred option and assessed within the Environmental Impact Statement (EIS) process following the RIT-T.
This RIT-T considers the net market benefits that are delivered by investments that increase the connection of renewables, such as overall dispatch and investment costs. The delivery of these benefits is in the long term interest of consumers.</td></tr>
<tr><td>We believe there must be a detailed assessment as to why consumers should pay for new generation in the identified REZs to be given subsidised access to the shared network. If this new generation seeks to locate in the western Victoria and southwest New South Wales REZs because these are “attractive locations for new generation projects” then the developers should include in their costs for the new generation, the costs of getting their product to market. There is</td><td>MEU p 10.</td></tr>
</table>

[152] AER, *Guidelines to make the Integrated System Plan actionable*, Final decision, August 2020. At https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20Guidelines%20to%20make%20the%20ISP%20actionable%20-%2025%20August%202020.pdf.

Summary of comment(s)	Submitter(s)	Response
no reason for consumers to pay for more increased interconnection than they need so that generators in the REZs can have a "free ride".		
Benefits of interconnector diversity and bushfire risk		
The value of route diversity should be estimated and quantified, as Transgrid has done for HumeLink.	EnergyAustralia p 2.	System resilience to events such as bushfires and line diversity has been considered for all options considered in this PADR. The ISP also notes that VNI West will deliver a more resilient power system, capable of operating more securely and efficiently across future weather conditions, including by providing more reserve during Heywood and Dederang–South Morang outages during extreme weather[B]. VNI 5A was assessed in the 2020 ISP and has not been progressed, partly due to these concerns (see Section 6.5).
Stakeholders would benefit from receiving further information on route selection in the PADR. We seek clarification on how the benefits of route diversity have been modelled, in terms of system resilience.	ERM Power p 3.	
It is likely that a better valuation of diversity would increase the benefits of additional interconnection, making timely building of a transmission backbone from Tasmania, through Victoria to New South Wales a minimal regret strategy.	Hydro Tasmania, p 2.	
There is significant value of diversifying the geographic interconnector routes between Victoria and New South Wales. The recent bushfires have demonstrated the compelling need for new transmission links and diversity of transmission paths.	Snowy Hydro, p 7.	
Option 5A, while close to existing transmission infrastructure, seems to be at greatest risk of fire danger of each of the three network options.	Donald McGauchie p 3	
The bushfire risk in the area of the VNI 7 corridor is minimal. This is particularly in contrast to the VNI 5 route, which traverses densely wooded and mountainous terrain with significant environmental value.	MRGC, p 5.	
Asset underutilisation/stranding risk and cost allocation		
Consumers are being asked to take the stranded asset risk for a 50-60 year asset that is going to support ~20-25 year solar and wind generation assets. Technological change over the next 20 years has a high chance of rendering a significant part of the proposed transmission capacity, redundant after the initial generation assets reach the end of their useful life, which, like coal generation today, may be less than their useful technical life given future technological innovation.	Energy Users Association of Australia (EUAA) p 4.	All market modelling has been undertaken consistently with the actionable ISP framework, as required. Moreover, AVP and Transgrid note the cumulative benefits in present value terms of Option 1 are expected to exceed the costs (in present value terms) by 2039-40 on a weighted basis, that is, the costs are expected to have been fully paid back by then.
It must be noted that high-cost, long-lived transmission assets also increase the risk and cost for consumers if underutilised by the market.	ERM Power p 1.	
There is considerable effort being applied into developing a hydrogen industry that might be fully established and operational within 10-20 years. If this new industry does get established, it might be that the output from many of these remotely located renewable generation sources will be used to generate hydrogen. So, in addition to the shorter lifespan of renewable generation potentially leading to under-utilisation (even stranding) of the longer lived transmission assets, the development of the hydrogen industry might well exacerbate this aspect of long lived assets that are made redundant (or severely under-utilised) but continue to be fully funded by consumers.	MEU p 6.	
While there is a high level of interest in developing the renewable energy resources in western New South Wales and northern Victoria, this should not lead to the automatic assumption that	EUAA pp 4-5.	

Summary of comment(s)	Submitter(s)	Response
charging consumers the full cost of transmission through network RABs is the "most efficient" or fair approach. We support the direction the AEMC is heading in with the CoGaTI reforms to ensure a sharing of the risk of new network connection. While this is by no means a perfect solution it is an important step towards developing a more equitable cost and risk sharing regime.		The issue of who pays for new transmission projects is one that is being considered and progressed at a policy level, and is outside of the scope of this RIT-T. Following the RIT-T, the ISP feedback loop ensures that the RIT-T's identified preferred option remains part of the optimal development path, and that the cost of the preferred option set out in the contingent project application must be no greater than the cost assessed in the feedback loop.
Consumer costs should be allocated first priority when considering regulated transmission network investment options, as it is consumers who bear the costs and risks for such investment.	ERM Power p 3.	
Consumers are not prepared to pay more for delivered electricity if the only benefit is an increased reliability of supply. Disagrees with the current test for whether new transmission assets are efficient being that it should provide a net market benefit because consumers are paying for a benefit to generators and there is no certainty that consumers will ever receive a benefit from this new generation which has received the cross-subsidy from consumers. Considers that it should be the beneficiary of the investment that should pay for the investment. While AEMO has made reference to the AEMC program (CoGaTI) that is intended to address this issue of consumers paying for a benefit enjoyed by generators, the MEU points out that this proposed framework does not avoid consumers continuing to cross-subsidise generators for network access.	MEU pp 1, 4.	
Modelling requests and comments		
Outline the sensitivity of the results should a significant OCGT or similar plant be announced and committed in and around Newcastle, Sydney or Wollongong.	EnergyAustralia p 2.	As outlined in Section 2.1, AVP and Transgrid have drawn directly on the latest available generation and storage information from AEMO, which includes both Kurri Kurri and Tallawarra B. AVP and Transgrid have not explicitly investigated a sensitivity involving a significant OCGT or similar plant announced and committed in and around Newcastle, Sydney or Wollongong but would be interested to hear from EnergyAustralia on whether this is still considered of interest (in light of both Kurri Kurri and Tallawarra B being reflected) and additional suggested detail on the potential plant.
Modelling of additional sensitivities under all five modelled scenarios (ie slow progress, step change, net zero 2050, electrification and *Hydrogen Superpower*) is warranted.	ERM Power p 4.	The three ISP scenarios modelled reflect significant variation in underlying assumptions. In light of the finding that Option 1 is the top-ranked option in all three scenarios (noting that it is effectively equally ranked with Option 2 under the *Hydrogen Superpower* scenario), AVP and Transgrid have not investigated additional sensitivities as part of this PADR.
Additional sensitivities should be included for: new generation assets having a shorter lifespan to traditional generation assets, with averages possibly as short as 25 years; estimates of future demand and consumption that are lower than AEMO's forecasts; and potential development of a hydrogen industry leaving existing assets stranded.	MEU p 6.	Assumed lifespans come directly from the AEMO generation and storage data set and AVP and Transgrid do not consider there to be a valid reason to depart from them as part of this PADR. AVP and Transgrid consider that the three scenarios investigated reflect a sufficient range of potential demand forecasts and so have not further investigated a standalone sensitivity on assumed demand.

Summary of comment(s)	Submitter(s)	Response
		The impact of the hydrogen industry taking off is considered to now be reflected in the *Hydrogen Superpower* scenario (which was not proposed at the time of the PSCR).
We suggest that AEMO/Transgrid should provide sensitivities for high and low discount rates, high and low capital costs, public policy or government announcements, and demand and supply shocks, to promote confidence in the RIT-T.	Origin, p 2.	AVP and Transgrid have investigated standalone sensitivities on discount rates and capital costs, both of which are not found to affect the identification of the preferred option. AVP and Transgrid have not considered standalone sensitivities relating to public policy or government announcements, and demand and supply shocks. AVP and Transgrid consider that the three scenarios investigated reflect a sufficient range of assumptions regarding these developments and so have not further investigated standalone sensitivities.
The PADR should consider and appropriately weight the scenarios. Weighing the scenarios would be consistent with the current RIT-T application guidelines.	Origin, p 3.	Scenario weighting is consistent with the recommendations of the 2022 ISP, which has been publicly consulted on. See Section 1.
Support AEMO and Transgrid adopting the 2019 forecasting and planning assumptions and five scenarios included in the 2020 ISP.	EnergyAustralia p 2.	AVP and Transgrid has used the 2021 IASR, which includes updated scenarios compared to those presented in the 2020 ISP. See Section 2.3.
AEMO/Transgrid should use the most up-to-date forecasts for the PADR, while remaining consistent with the ISP in terms of assumptions. It would also be useful to provide a brief explanation where the inputs used in differ, to promote understanding of how the PADR modelling differs from the ISP outcomes.	Origin, p 2.	
Requests for further transparency of estimates		
Request specific deep dives into the market modelling assumptions and dispatch outcomes for hydro and pumped hydro assets, including any investment made subsequent to Snowy 2.0. In particular, we request more information on assumptions around perfect foresight (relative to practical dispatch outcomes) and the materiality of the impact these assumptions have on the economic evaluation.	EnergyAustralia p 2.	AVP and Transgrid have scheduled stakeholder consultation sessions during July 2022 that will allow parties to deep dive into the analysis in the PADR.
Detail on assumed asset lives.	EnergyAustralia p 3.	See accompanying NPV model released alongside this PADR.
WACC	EnergyAustralia p 3.	See Section 8.4.
Opex assumptions when determining annualized values.	EnergyAustralia p 3.	Annual routine operating and maintenance costs are assumed to be 1% of capital costs for transmission assets, including early works, substation works, lines works and modular power flow controllers (but excludes land related costs and biodiversity offset costs). See Section 6.1.
Define what constraints are binding, after the augmentation, for each option – and how the augmented interconnector will be utilized.	EnergyAustralia p 3.	Please refer to the accompanying EY market modelling report for duration curves.
Describe the proportion of annual regional energy that will be met locally, and that supplied by imports, in all the scenarios, and therefore how inter-regional transmission charges (also known as modified load export charges, MLEC) will influence who pays for the investment over time.	EnergyAustralia p 3.	AVP and Transgrid note that the RIT-T is required to look at market benefits across the NEM as a whole to find the optimal solution, without assessing inter-regional impacts. Cost allocation, and the sharing of risk, sits outside of the

Summary of comment(s)	Submitter(s)	Response
		RIT-T process and changes to the regulatory framework in this regard are currently being considered by governments and regulators.
Detail on the impact of VNI West investment on supplying New South Wales and Victoria peak summer and winter demand.	EnergyAustralia p 3.	The PADR and accompanying EY market modelling provide detail on how the NEM is expected to be affected by the options.
How inter-regional loss factor equations will change, and the benefits (or costs) of improved (or increased) transmission losses.	EnergyAustralia p 3.	The PADR market modelling captures changes in inter-regional network losses due to changing dispatch patterns enabled by the credible options as part of the overall change to fuel consumption. Changes in intra-regional network losses due to the credible options have been captured in the constraint equations, as the equations were updated to reflect the impact of the options. As such, no separate category of changes in network losses is included in the PADR analysis.
How notional export/import increases in terms of supply to Sydney or Melbourne.	EnergyAustralia p 4.	The limits assumed are consistent with the assumptions used in the 2022 ISP (as outlined in the 2021 IASR).
Articulate costs of land and easement.	EnergyAustralia p 3.	Option cost breakdowns have been provided. See Table 4, Section 6.1.
Suggest that AEMO and Transgrid publish as much information on the inputs and outputs as possible with the PADR. We consider that the full models should be made available with the PADR to enable stakeholders to provide more informed and useful feedback.	Origin, p 3.	AVP and Transgrid have endeavoured to include sufficient information in this PADR and associated attachments to provide transparency on the RIT-T inputs, assumptions, and modelling results. Additional detail on the scenarios modelled, and assumptions drawn upon, can be found in the 2021 AEMO IASR.
Recommended that all credible options considered by the proponent should be outlined. For instance, it is not clear to stakeholders whether low-cost options in the 220 kV network were considered.	ERM Power p 3.	Options considered but not progressed are detailed in Section 6.5.
The MEU considers that all options considered need to be included in the table and reasons provided why some options are not considered to be credible.	MEU p 7.	
Preferences for specific options		
VNI 5A		
Prefer a version of VNI 5A (if costs can be reduced in light of it involving an upgrade of the existing network).	MEU p 11.	VNI 5A was evaluated as part of the 2020 ISP and discounted (see Section 6.5.
VNI 6		
VNI 6 is preferred to VNI 7 as it presents lower costs for consumers but provides the same interregional transfer capacity.	ERM Power p 4.	The VNI 6 option put forward in the PSCR and 2020 ISP was ruled out in the 2022 ISP, as outlined in Section 6.5. It has therefore no longer been considered in this RIT-T.
If VNI 5A cannot be reduced in cost or cannot provide sufficient capacity, VNI 6 provides the maximum transfer capacities for a lower cost compared to VNI 7 and VNI 8.	MEU p 12.	

Summary of comment(s)	Submitter(s)	Response
Supports VNI 6 because it opens up a significant new renewable energy development area to future network connection opportunities that were unavailable until now.	Neoen, p 2.	
VNI 7		
VNI 7 runs through lower value agricultural land well suited to solar power generation, with a demonstrated track record of major project planning approval.	Donald McGauchie p 3.	This option, now referred to as 'VNI West (via Kerang)' or simply 'VNI West', is the preferred option in this PADR – see Sections 8 and 9.
VNI 7 would link the largest and most capable REZ in Victoria to the interstate grid. VNI 7 also has relatively low value agricultural land, is sparsely populated, has strong support from local councils and has strong solar resources.	Gannawarra Shire Council, pp 1-2.	
VNI 7 with expansion A is preferred. This option would support the growth of large-scale solar farm development in the region. VNI 7 has suitable topography, and council and community support. VNI 7 would also resolve industry supply and access concerns.	MRIC, pp 1, 12.	
VNI 7 with expansion A would provide the most benefits to the system as a whole and would result in the swift development of significant amounts of renewable large scale solar power generation in the Murray REZ.	MRGC, p 3.	
Considers that development of VNI 7 is more likely to unlock investment and provide national and Victorian economic benefits associated with Australia's critical energy transition.	Pacific Hydro, p 3.	
VNI 7 is preferred, which provides Victoria with access to Snowy Hydro's existing and future generation capacity, and helps alleviate constraints from renewable investment in the north-west or central areas of Victoria. VNI 7 option will be critical in releasing the significant amount of renewable investment in West Murray, which is currently in a remote and electrically weak part of the NEM.	Snowy Hydro, p 2.	
Other		
There is risk that the rigor of the RIT-T process is being compromised and regulatory oversight is being removed in order to fast-track project development.	ERM Power pp 3.	The analysis in this PADR fully aligns with the requirements of the actionable ISP process, including the AER cost benefit analysis guidelines for making the ISP actionable. In addition, as part of the contingent project process, Transgrid will seek a 'feedback loop' confirmation from AEMO in-line with the new actionable ISP framework ahead of lodging a contingent project application for investment in VNI West.
Unused capacity from large scale solar projects in the north-west of Victoria could be used to generate hydrogen for use in the local industry, which could assist with storage to flatten the peaks of production to provide better stability from renewables.	Mallee Regional Innovation Centre (MRIC) pp 10-11.	Noted, but consider this development to be speculative at this point and outside the scope of the benefits that can be included in the RIT-T.
The RIT-T must be carried out with regard to least-cost NEM planning and not simply least-cost Victorian planning. Hydro Tasmania strongly supports "more efficient sharing of resources between NEM regions".	Hydro Tasmania p 4.	The market modelling undertaken for this PADR is consistent with least-cost NEM planning.

Summary of comment(s)	Submitter(s)	Response
Operational impacts of this project on existing network function.	AusNet Services p 3.	The operational impacts of each option have been assessed in-detail as part of the PADR. It is these impacts that drive the market benefits estimated for each option. All options have been designed to meet all relevant standards, including for safety.
Safety aspects of the construction for various options that may require working within live terminal stations and adjacent to live high voltage transmission lines to be considered.	AusNet Services p 3.	Any work would be undertaken in accordance with all relevant design and safety standards.

A. AEMO, 2020 ISP Appendix 3. Network investments, July 2020, p 66.
B. AEMO, 2022 ISP Appendix 4. System operability, June 2022, p 20-23.